OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **February 28, 2012**

TO: Phillip Fielder, P.E., Permits & Engineering Group Manager, Air Quality

THROUGH: Kendal Stegmann, Sr Environmental Manager, Compliance and Enforcement

THROUGH: David Schutz, P.E., New Source Permits Section

THROUGH: Peer Review

FROM: Phillip Martin, P.E., Manager, Existing Source Permits Section

SUBJECT: Evaluation of Permit Application No. **98-014-C (M-19) PSD**
Holly Refining & Marketing – Tulsa LLC (Holly)
Holly Tulsa Refinery West (SIC 2911)
1700 South Union
Tulsa, Tulsa County, OK (36.138° N, 96.011° W)

SECTION I. INTRODUCTION

Holly Refining & Marketing – Tulsa LLC (Holly) has submitted an application for a construction permit for a proposed new Boiler #10. The boiler will be installed due to a Consent Decree with EPA. The facility is currently operating as authorized by Permit No. 98-014-TV (M-18), which was issued on May 18, 2011.

The proposed Boiler #10 will be subject to NSPS Subpart Db, Subpart Ja, and 40 CFR Part 63 Subpart DDDDD.

Since this project will result in a significant emission increase and a significant net emissions increase for CO_{2e} emissions, it is subject to PSD for CO_{2e} including BACT for the new Boiler #10. The project will not result in a significant emission increase or a significant net emissions increase for any criteria pollutant.

The permit memorandum for this modification will only address the issues concerning the requested modification. However, the permit and associated specific conditions will contain all of the applicable requirements from the previous permits.

SECTION II. DESCRIPTION OF PROCESSES

Holly's crude is received by pipeline and tanker truck. The crude is a mixture of purchased crude oils from various sources, which, when blended, has the required properties to make the lubricating oil products. Holly currently is operated primarily to produce high quality lubricating oils. Refinery fuel gases, propane, butane, isobutane, normal butane, gasolines, kerosene, No. 2 fuel oil, paraffin wax, petroleum coke, and Lube Extracted Feedstock (LEF) are some of the current byproducts from making the lube oils. LEF is a mixture of unfinished streams that may also be transferred to third party purchasers.

The specific types of refining process and support facilities in current use in the Holly Refinery are discussed in the following paragraphs. All of the process units and associated support equipment at Holly operate as a whole (one primary operating scenario). Individual units or pieces of equipment undergo periodic scheduled periods of shutdown for maintenance, but no one unit or piece of equipment has any permit restrictions on potential operating hours. Therefore, total potential operating hours per year for all equipment is 24 hours per day, seven days per week, for every day of the year.

CRUDE DISTILLATION

The Crude Distillation Unit is the first process and is used to separate crude oil or mixtures of crude and other purchased crude fractions into specific boiling-range streams suitable either for further processing in downstream units or in some cases, for direct sale after mild treating or blending. The primary equipment associated with this operation is a main atmospheric pressure fractionator, a light ends fractionator called the "stabilizer tower," and two in-series vacuum distillation units. The atmospheric tower recovers streams that boil at approximately atmospheric pressure. The stabilizer tower feeds overhead gas to the crude tower and, at high pressure, effects a first separation of true gases (which go to the refinery fuel gas system) from crude gasoline. The vacuum towers recover high boiling point fractions that can be recovered only by lowering the pressure and operating at elevated temperatures. The energy for the distillation steps is provided by a main crude heater and two vacuum charge heaters, all gas fired. Other equipment important to crude and vacuum distillation is an extensive heat exchange system, a crude desalter system, and a vacuum producing system.

LIGHT ENDS RECOVERY UNIT (LERU)

The light gases from the Crude Unit Stabilizer are processed in a deethanizer tower and a depropanizer tower in the LERU. The deethanizer is a high-pressure fractionator that separates ethane and lighter fuel gases from propane and heavier hydrocarbons. The depropanizer tower is a pressurized tower that fractionates deethanizer bottoms into a liquid propane stream and a liquid mixed butane/pentane stream. The propane is treated with potassium hydroxide for sulfur removal, stored in tankage, and sold as commercial liquefied petroleum gas (LPG). The mixed butane/pentane from the depropanizer is stored in pressurized storage prior to further fractionation. Energy for the LERU process is provided by steam passing through reboilers (heat exchangers).

<u>ISOMERIZATION UNIT TOWERS</u>
The isomerization reactors are shut down, but an associated fractionation system for separating manufactured and natural isobutane from normal butane remains in operation. Feed is the LERU butane/pentane stream from storage. The butane/pentane is brought from storage and treated with potassium hydroxide for sulfur removal and fed to the deisobutanizer which first creates a propane/isobutane feed for a depropanizer that separates propane as an overhead stream from isobutane as a bottoms stream. The propane is stored and sold as LPG. The isobutane is stored in a pressurized tank and sold as isobutane. Deisobutanizer bottoms are fed to a debutanizer for recovery of normal-butane as an overhead product (to sales or to gasoline blending), and pentane bottoms which goes to gasoline blending.

<u>DEPENTANIZER AND NAPHTHA SPLITTER</u>
The Crude Unit Stabilizer tower bottoms charge the fraction tower called the de-pentanizer. This de-pentanizer makes an overhead liquid stream called light straight run gasoline which goes to gasoline blending. Bottoms, called naphtha, are split via level control with part going to the Unifiner and part to Lube Extracted Feedstock (LEF) and shipped to the Sunoco Toledo Refinery or other third party purchasers. Splitter bottoms join crude naphtha as feed to the downstream Unifiner Unit. Energy for the de-pentanizer is supplied by a gas fired heater.

<u>UNIFINER</u>
The Unifiner Unit has the purpose of treating naphtha from the Crude Unit and the depentanizer bottoms in preparation for conversion to high-octane gasoline in the downstream No. 2 Platformer Unit. The Unifiner includes a hydrogen-treating reactor that removes sulfur and other contaminants that would be detrimental to the downstream Platformer. Other major equipment includes a hydrogen compressor, gas/liquid reactor effluent separator vessels, a stripper column to remove gases from the reactor product, and heat exchange systems. Two gas-fired heaters supply energy for the reactors and stripper column.

<u>NO. 2 PLATFORMER</u>
Unifiner effluent charges the Platformer, which catalytically converts the low-octane paraffin hydrocarbons to high-octane aromatics for gasoline blending. Naphtha feed is preheated by heat exchange, charged to a series of four endothermic catalytic reactors (four gas-fired heaters supply the heat of reaction), flashed to separate gas from product, and distilled through a debutanizer tower. The debutanizer is energized by a gas-fired reboiler heater. Hydrogen and other light gases are by-products that are primarily sent to refinery fuel gas, although a hydrogen-rich stream is used to provide hydrogen to the Unifiner reactors and the lube hydrotreater.

<u>DEASPHALTER</u>
The Deasphalter Unit processes heavy bottoms from the second stage vacuum tower at the Crude Unit. Two parallel solvent extraction towers mix feed and propane solvent and produce two streams, one that is paraffinic and suitable as feedstock for lube manufacture in the downstream Lube Extraction Unit, and a second that is asphaltic that charges the Coker Unit. Some of the paraffin stream is also blended to the lube-extracted feedstock that is exported by pipeline to the Sunoco Toledo Refinery or third party purchasers. The Deasphalter Unit employs other towers, vessels, pumps, heat exchangers, etc., to recover propane solvent from the product streams. Propane is recycled to the front-end extraction towers. Two gas fired process heaters and steam

from the refinery system provide energy for the extraction process and for solvent recovery operations.

LUBE OIL EXTRACTION AND HYDROGENATION

This unit is charged with vacuum gas oil fractions and paraffinic deasphalted oil which flows into two parallel counter-current solvent extraction towers that utilize furfural as a solvent. As a result, two streams are produced, a waxy paraffinic stream suitable for lube oil manufacture and an aromatic stream that is either blended with lube oil extracted feedstock for pipeline shipment to the Sunoco Toledo Refinery or sold as extract product. The waxy paraffinic stream is fed to a hydrogenation unit to improve its stability and remove impurities before going to a downstream dewaxing operation. The hydrotreater is a fixed bed catalytic unit that uses hydrogen from the No. 2 Platformer. The unit employs towers, vessels, heat exchangers, pumps, etc., to remove and recycle the furfural solvent from the product streams. Three gas-fired heaters provide energy for the process.

MEK DEWAXING UNIT

This unit removes wax from the hydrotreated paraffins from the Lube Extraction Unit. The process employs two solvents in mixture, toluene and methyl-ethyl-ketone. Fabric filters on rotating drums are used to physically separate wax from oil. A propane refrigeration system provides cooling to effect wax precipitation out of oil/wax solutions. Paraffin streams are fed in blocked out batches (the boiling range of the various batches having been set when recovered as separate streams at the Crude Unit vacuum towers). The dewaxed oil batches are stored and used for finished lube oil blending. The deoiled wax batches are stored and sold as various melt point products. Waxes with a melt point above about 116°F are further processed through a downstream Percolation Filtration Unit. The unit equipment includes oil/solvent contactors, rotating drum fabric filters, towers and vessels for solvent recovery and recycle, a propane refrigeration compressor system, a flue gas compressor system associated with the fabric filters, pumps, heat exchangers, etc. Two gas fired process heaters are employed, one for oil/solvent separation, and one for soft wax/solvent separation.

COKER UNIT

Holly's Coker Unit produces solid coke particles in a batch process. The Coker Unit equipment list includes two gas fired process heaters, two coke drums, a main fractionator, and other towers, vessels, pumps, heat exchangers, etc. The Coker Unit alternates the process between two vessels called drums. One drum is being charged for processing while the other is being emptied or "de-headed." The process begins by charging one of the coke drums with the asphaltic stream from the Deasphalting Unit. The process thermally separates the heavy molecules into carbon (coke) and light hydrocarbons. The charge is heated to 900°F using two gas-fired process heaters and then is allowed to have residence time while the coke and the light hydrocarbons separate. The light hydrocarbons flows/charges the product fractionation system (a part of the Coker Unit) for separation into gas for refinery fuel, and liquids which are pipelined to the Sunoco Toledo Refinery or to third party purchasers, and gasoline for recovery back through the Crude Unit stabilizer. After a drum is de-headed it is cleaned out with steam for the next batch. Coke is stored in piles on-site, for bulk shipment by rail or trucks. Air emissions from handling the finished coke are insignificant.

LUBE/WAX BLENDING AND SALES/SERVICE OPERATIONS

This refinery's primary purpose is to produce finished paraffinic lubricating oils. These waxes are also an important by-product of lube oil manufacturing process. To provide the specialty products required by Holly's diverse customers, there is a product blending and shipping operation at the site. The blending primarily occurs in cone roof tank areas. Packaging and package storage is conducted in the Lube Service Center building. Shipment is by bulk in tank trucks and tank railcars.

STEAM GENERATION

In an area called "No. 5 Boilerhouse" (No. 4 Boilerhouse was dismantled in the 1970s), there are seven gas-fired boilers that produce steam for general refinery use. There are seven individual boiler units numbered Nos. 1, 2, 3, 4, 7, 8, and 9 in the No. 5 Boilerhouse.

WASTEWATER TREATMENT

Facility wastewaters are conveyed in combined storm/process sewers, through oil/water separators and to a treatment area that employs storm surge capacity, clarification, dissolved air floatation, equalization, and aerobic waste digestion. Treated water is discharged to the Arkansas River. Recovered sludges are deoiled at a centrifuge facility and the oil is fed to the Coker Unit or Crude Unit.

COOLING TOWERS

The refinery employs 7 non-contact cooling towers. These are systems that circulate captive waters that provide a heat sink for various process units or equipment. Water is circulated through heat exchangers to indirectly cool hydrocarbon or other streams. Hot water from these exchangers is collected by pipelines and sprayed over packed towers in counter current flow to atmospheric air. The evaporation of a portion of the hot (typically 100 to 120°F) circulated water provides cooling to about 85°F (summer) for recirculation back to the heat exchangers. The white plumes observed from these towers are the evaporated water that sometimes re-condenses cloud-like at certain atmospheric conditions. The cooling towers have not used chrome-based systems since before 1994, are not subject to MACT Subpart Q, and are trivial sources named in Appendix J of OAC 252:100.

FLARE STACKS

The refinery employs four vertical, piloted flare stacks for the emergency containment and combustion of certain hydrocarbon releases. Various Holly process equipment is fitted with pressure relief valves to protect against overpressure conditions. These pressure relief valve outlets discharge into a gas collection flare piping system. Each flare stack uses a continuous pilot light that assures ignition of any gaseous discharges. Each flare also uses a steam system that supplies a constant source of steam for mixing with the gas being flared (as needed) to reduce/prevent the combustion products from smoking.

LOGISTICS AND STORAGE

The Holly logistics system involves feed and product receipt and shipment systems, as well as extensive internal movements. Crude feed material is primarily received by pipeline into large tanks. Product shipments are also made by pipeline, tank truck, rail tank car, and package truck trailer. This refinery does not have a marine terminal. There is an extensive storage tank system that handles crude feeds, finished products, and process intermediates. Types of material are generally in common geographical areas, but there are many exceptions due to the long history of the site.

SULFUR AND OTHER IMPURITY TREATMENTS
This refinery processes feeds that are low in sulfur content, and does not employ a fluid catalytic cracker or a large hydrotreater or hydrocracker and therefore does not require units associated with other typical refineries such as amine gas scrubbers, sour water strippers, and elemental sulfur recovery units. Refinery process offgases often contain significant amounts of sulfur. These offgases flow to a refinery fuel gas (RFG) system and can be burned only in grandfathered fuel-burning units. Refined product sulfur impurities are addressed within specific process units by caustic or chemical treatment steps.

SECTION III. EQUIPMENT AND EMISSIONS

The proposed new Boiler #10, rated at a maximum of 214.6 MMBtu/hr, is capable of producing 150,000 lb/hr of steam. The boiler will burn Oklahoma natural gas until such time as the refinery fuel gas cleanup project is completed as required by a Consent Decree with EPA. The fuel gas for the boiler must be compliant with NSPS Subpart Ja. Ja requires the fuel gas to contain 162 ppmv H_2S or less on a 3-hour rolling average basis and 60 ppmv H_2S or less on a 365 successive calendar day rolling average basis. The lb/MMBtu calculation for SO_2 was based on 900 MMBtu/scf refinery gas.

Emissions from the unit will consist of standard combustion emissions: NO_x, CO, PM_{10}, VOC, SO_2, greenhouse gases (asCO2e) and trace amounts of HAPs. Emission factor data and potential emissions from the new boiler are summarized in the tables below. The design incorporates low NOx burners and flue gas recirculation (FGR) for improved unit efficiency and to minimize NOx emissions.

Emission Factor Data

Pollutant	Emission Factor Lb/MMBtu	Source
NOx	0.027	Manufacturer Data
VOC	0.0055	AP-42, Table 1.4-2
PM_{10}	0.0076	AP-42, Table 1.4-2
CO	0.084	AP-42, Table 1.4-2
SO_2	0.031 3-hr average 0.01125 365-day rolling avg.	Subpart Ja
CO_2e	130.6	EPA GHG MRR

EUG 2a: Boilers Subject to NSPS Subpart Ja

Point ID	NOx		VOC		PM_{10}		CO		SO_2		CO_2e	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
#10 boiler	5.79	25.4	1.18	5.17	1.63	7.14	18.0	78.96	6.65	10.57	28,031	122,776

SECTION IV. PSD REVIEW

A. Project Emission Increases

A project is not a major modification if it does not cause a significant emissions increase or a significant net emission increase. A significant emissions increase of a regulated NSR pollutant will occur if the sum of emissions increases for each EU equals or exceeds the amount that is significant for that pollutant. For each EU, the emission increases are based on the difference between the "potential emissions" (PTE) and the "baseline actual emissions" (BAE). Facilities that use the PTE for existing units are not subject to the recordkeeping requirements in OAC 252:100-8-36.2(c). New emissions units must use their PTE and BAE are equal to zero.

Baseline Actual Emissions (BAE) are equal to zero for the proposed boiler. Project emission increases include emissions from newly constructed emission units, existing emission units proposed for modification, existing emission units that are debottlenecked, and other associated emission increases. No existing emission units are proposed for modification or are debottlenecked and there are no other associated emission increases.

If the project results in a significant emission increase, the project has to be reviewed for a significant net emission increase. Net emissions increases include the increase in emissions from a particular change and any other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable. An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs within 3 years prior to the date that the increase from a particular change occurs. An increase or decrease in actual emissions is creditable only if the AQD has not relied on it in issuing a PSD permit for the source which is in effect when the increase in actual emissions from the particular change occurs.

Project Emission Increases

	NO_X	**VOC**	**$PM_{10}/PM_{2.5}$**	**CO**	**SO_2**	**CO_2e**
Sources	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**
BAE	0	0	0	0	0	0
PTE	25.4	5.17	7.14	78.96	10.57	122,776
Increases	25.4	5.17	7.14	78.96	10.57	122,776
SER	**40**	**40**	**15/10**	**100**	**40**	**75,000**
< SER	Yes	Yes	Yes	Yes	Yes	**No**

Since the project results in a significant emission increase for CO_2e, a review of the net emission increases is required for CO_2e.

B. Project Net Emission Increases

HRMT has not shut down any sources in the last three years so a netting analysis has not been performed. The project results in a significant net emission increase for CO_2e.

C. BACT

Since the project results in a significant net emission increase for CO_2e the project is subject to PSD for CO_2e which includes BACT, modeling, and monitoring, if applicable. There are currently no applicable modeling or monitoring requirements for CO_2e. A source shall apply BACT for each regulated NSR pollutant for which a significant net emissions increase occurs. BACT shall apply to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit. The affected EU subject to BACT is the proposed Boiler #10.

For the purpose of this analysis, GHG is assumed to be composed primarily of CO_2, with much smaller quantities of CH_4 and N_2O. Under EPA's new guidelines for GHG BACT, the typical top-down analysis approach is to be followed. Since CO_2 is not typically feasible to control, the available control options focus on potential improved process efficiency, leading to improved fuel efficiency, rather than end-of-stack types of control systems.

One end-of-stack control option to be considered is geologic sequestration of GHG. However, sequestration is not yet commercially available and appropriate geologic formations have not been proven for long-term underground storage in the vicinity of Tulsa, OK. In addition, collateral environmental impacts that could result from sequestration have not been evaluated and require further study. Therefore, geologic sequestration is not considered to be a technically feasible control option at this time and is therefore eliminated from further consideration in this analysis. In addition, since sequestration is not yet commercially available, it is not possible to accurately estimate control costs.

The only remaining control option to consider is efficiency. EPA's *GHG Control Measure White Paper for Large Industrial/Commercial/Institutional Boilers* discusses various options for improving efficiency. The options identified below are ranked in descending order of efficiency. The boiler proposed for this project is designed for 83.5% efficiency at 100% load and incorporates optional components for increased energy efficiency. HRMT has proposed a 10% safety factor to allow for operating at various loads. An efficiency of 75% was used to calculate the 206 lb CO_2e / 1000 lb steam produced BACT limit.

1) Increased heat recovery to preheat boiler feedwater (economizer) or to preheat combustion air (preheater). Per EPA's white paper, capturing the waste heat of exhaust gases increases system efficiency by about 1% for each 40°F reduction in temperature. The proposed system includes an economizer designed for over 300°F reduction in exhaust temperature.
2) Optimization, instrumentation, and controls may be used to optimize combustion, including providing control of air/fuel ratio, thus reducing wasteful excess air by burning closer to stoichiometric, and compensating for changes in air temperature, humidity, atmospheric pressure, and fuel characteristics. EPA's *GHG Control Measure White Paper for Large Industrial/Commercial/Institutional Boilers* indicates an additional 0.5 - 5% improvement in system efficiency. The proposed system includes a Siemens 353 Series microprocessor combustion and feedwater control system to provide a high level of system efficiency.
3) Other options from EPA's white paper applicable to retrofits are not discussed here since the proposed boiler is a new unit.

Under the top-down approach, the highest ranking option (economizer) is considered first and is evaluated on the basis of cost and collateral environmental impact. Since the highest ranking option is incorporated in the proposed boiler, costs have not been evaluated. The second highest ranking option (optimization, instrumentation, and controls) has also been included.

Thus, the natural gas and refinery gas-fired boiler, with use of an economizer and microprocessor based control system with emissions less than 206 lb CO_2e / 1000 lb steam produced (30 day rolling average), is accepted as BACT. The steam produced is at 625 psig and 750°F. The BACT limit includes startup and shutdown.

SECTION V. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-2 (Incorporation by Reference) [Applicable]
This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Subchapter 3 enumerates the primary and secondary ambient air quality standards and the significant deterioration increments. At this time, all of Oklahoma is in "attainment" of these standards.

OAC 252:100-5 (Registration, Emissions Inventory and Annual Operating Fees) [Applicable]
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories were submitted and fees paid for previous years as required.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
This subchapter sets forth permit application fees and the substantive requirements for operating permits required by 40 CFR Part 70 sources. Part 5 includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility that result in emissions not authorized in the permit and that exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities refer to those individual emission units either listed in Appendix I or whose actual calendar year emissions do not exceed the following limits.

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for a HAP that the EPA may establish by rule

Emission limitations and operational requirements necessary to assure compliance with all applicable requirements for all sources are taken from the operating permit applications, or developed from the applicable requirement.

OAC 252:100-9 (Excess Emissions Reporting Requirements) [Applicable]
Except as provided in OAC 252:100-9-7(a)(1), the owner or operator of a source of excess emissions shall notify the Director as soon as possible but no later than 4:30 p.m. the following working day of the first occurrence of excess emissions in each excess emission event. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. Request for affirmative defense, as described in OAC 252:100-9-8, shall be included in the excess emissions event report. Additional reporting may be required in the case of ongoing emission events and in the case of excess emissions reporting required by 40 CFR Parts 60, 61, or 63.

OAC 252:100-13 (Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter (PM)) [Applicable]
Section 19-4 regulates emissions of PM from new and existing fuel-burning equipment, with emission limits based on maximum design heat input rating. Appendix C specifies a PM emission limitation of 0.60 lbs/MMBtu for all equipment at this facility with a heat input rating of 10 Million BTU per hour (MMBTUH) or less and sets a most restrictive rating of 0.10 lb/MMBtu for the largest equipment. Fuel-burning equipment is defined in OAC 252:100-1 as "combustion devices used to convert fuel or wastes to usable heat or power." Thus, the fuel-burning equipment listed in EUGs 1, 2, 3, 4, 5, 6, 36, 37, and 38 is subject to the requirements of this subchapter. Gas-fired fuel-burning equipment at the facility burns either RFG or commercial grade natural gas (or its equal). RFG is a mixture of various process unit light gases that contain hydrogen (non-particle emitting) and methane through butane light hydrocarbons. RFG is a dry gas, free of liquid particles due to liquid knockout collection drums prior to final fuel end use. Dry gas is recognized by EPA to be at least as clean burning, as to particulates, as commercial grade natural gas. Since AP-42 has no distinct factor for dry gas mixtures the following demonstrations are based on the natural gas (methane) factors. Table 1.4-2 of AP-42 lists the total PM emission factor for equipment burning natural gas to be 7.6 lbs/10^6ft^3. If we make the conservatively high assumption that PM emissions are related only to volume and that heat content has no effect, then the gas with the highest PM emission in units of pounds per MMBtu will be the gas with the lowest heating value. The lowest heating value found is 584 BTU/DSCF, implying emissions of 0.013 lbs PM/MMBTU. This conservative result is still a factor of 10 below the 0.10 lb/MMBtu most restrictive allowance identified in the introductory paragraph for any equipment at the facility.

The highest emission factor suggested in Table 3.3-1 and Table 3.4-1 of AP-42 for either gas-fired or diesel-fired reciprocating engines is 0.31 lbs/MMBtu. The largest engine in EUG 36, EUG 38, or in the Insignificant Activity group has a heat rating less than 5 MMBtu/hr. All engines are thus subject to the least restrictive standard of 0.6 lbs/MMBtu and all are in compliance.

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences that consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours and according to the other exceptions defined in this subchapter. In no case shall the average of any six-minute period exceed 60% opacity. When burning natural gas there is very little possibility of exceeding these standards and compliance with the standard is presumed. Degreasing operations, painting operations which filter particulate emissions, non-heat set printing operations, other non-heat set evaporative VOC sources, petroleum product storage tanks, glycol dehydrators and sources which are vented inside a building which is usually occupied may be presumed to be in compliance with any opacity limit of 20% or greater. Emission units that are deemed as ‘potentially very low or nonexistent visible emissions’ are not subject to monitoring requirements. For units that qualify as ‘potentially very low or nonexistent visible emissions’, the facility will conduct qualitative opacity assessments in lieu of Reference Method 9 testing. Compliance with opacity limitations is confirmed by plant observations according to the opacity monitoring schedule.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originated in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or to interfere with the maintenance of air quality standards. Under normal operating conditions, this facility has negligible potential to violate this requirement; therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) (Applicable]
Part 2 concerns ambient concentrations of SO_2 and H_2S for new and existing equipment. Emissions of sulfur compounds from any existing facility shall not result in an ambient air concentration outside the facility property line greater than those specified at §31-7(a) as to SO_2 and §31-7(b) as to H_2S. There are no significant H_2S emission points.

The facility claims to be in compliance based on AERMOD ambient air quality modeling submitted to the Air Quality Division in February 2003. AERMOD modeling, using building and stack downwash features, was applied to area-wide ambient air receptors. Actual daily emissions from Holly were modeled with concurrent meteorology to reflect actual impacts.

Additional AERMOD modeling was applied to area-wide ambient air receptors. Actual daily emissions from Holly were modeled with coincident meteorology from the past five years. Exceedances were shown in a small area immediately east of Holly. Modeled concentrations were compared to monitored concentrations from EPA/DEQ monitoring sites 501, 175, and 235, showing that AERMOD modeled impacts at the monitors exceeded the actual measured concentrations. Holly’s consultant (ERM) refers to these as “false exceedances” of the 24-hr 130 $\mu g/m^3$ standard.

ERM and Holly concluded that because the AERMOD model over-predicts ambient concentrations, modeling data alone cannot be relied upon to demonstrate ongoing compliance. To prevent exceedances (shown by EPA/DEQ monitoring) and to determine compliance with the ambient air quality standards of §31-7(a), Holly will conduct monitoring of the ambient air quality and take action as described below. The knowledge of what significant variables affect refinery SO_2 emissions played a major role in determining that the actions described in the following will be adequate to keep the facility's SO_2 emissions in compliance.

1) Monitor SO_2 ambient air concentrations measured at the east perimeter of the refinery. This will consist of a portable instrument operated for a period of 2 hours during each day. An average shall be calculated for each hour of measurement. Compliance with the 24-hour concentration limit will be presumed as long as all hourly averages are below the detection limit of 0.4 ppmv SO_2.

2) If either of the two hourly averages calculated pursuant to paragraph 1 is 0.4 ppmv or greater, Holly shall monitor for a second two-hour period on the same calendar day and calculate hourly averages for this second monitoring period. For any calendar day in which three of the four hourly calculated averages exceed 0.4 ppmv, Holly shall review relevant information including, but not necessarily limited to, meteorological data, rail usage, and refinery operations, for the time period during which the measurements were recorded to determine the cause of the measured values. This process is identified as a "root cause analysis."

3) Monitor meteorological data from the Tulsa office of the National Weather Service.

4) Holly will submit a report that lists all monitoring data, meteorological data, and any calculations performed to the DEQ Regional Office at Tulsa by the 30th day following the end of each two-calendar-month period. Upon completion of one year of such bi-monthly reporting without an exceedance, reporting shall reduce to quarterly, with reports due by the 30th day following each three-calendar-month period. Upon completion of one year of such quarterly reporting without an exceedance, reporting shall reduce to semi-annual, with reports due by the 30th day following each six-calendar-month period.

5) Excess Emissions will be reported pursuant to the requirements of OAC 252:100-9.

Part 5 contains new equipment standards. As used here, "new" refers to any equipment constructed or modified after July 1, 1972, with certain exceptions, as defined in §31-2.

Paragraph 31-25(a)(1) covers gas-fired fuel-burning equipment. The equipment listed below is presumed in compliance because this equipment burns only commercial pipeline quality natural gas or gas that is equal or better. Boiler #10 is subject to NSPS Subpart Ja which is more stringent than Subchapter 31and will comply with the provisions of this subchapter.

1. #7 Boiler
2. #8 Boiler
3. #9 Boiler
4. #2 Plat PH-5 heater
5. Coker H-3 heater
6. Coker B-1 heater
7. MEK H-101heater
8. Boiler #10

The following pieces of fuel-burning equipment are not subject to OAC 252:100-31-25(a)(1) because the units were constructed prior to, and have not been modified since, the applicability date of July 1, 1972.

EU	Point ID	Const. Date
105A	#1 Boiler	1948
105B	#2 Boiler	1948
106A	#3 Boiler	1954
106B	#4 Boiler	1957
201N	CDU H-1,N,#7	1961
201S	CDU H-1,S,#8	1961
206	Unifiner H-2	1957
207	Unifiner H-3	1957
209	#2 Plat PH-1/2	1957
210	#2 Plat PH-3	1957
211	#2 Plat PH-4	1957

EU	Point ID	Const. Date
214	#2 Plat PH-7	1971
238	PDA B-30	1956
240	PDA B-40	1962
242	LEU H101	1963
244	LEU H-201	1963
246	MEK H-2	1959
202	CDU H-2	1961
203	CDU H-3	1961
243N	LEU H-102 North	1963
243S	LEU H-102 South	1963
213	#2 Plat PH-6	1957

It is not clear whether all of the fuel-burning equipment in EUG 36 and EUG 38 is new or existing, but the calculations supporting the emission estimates for these EUGs clearly demonstrate that the SO_2 emissions satisfy the standard of 0.8 lbs/MMBtu set by §25(a)(2).

<u>Section 31-26</u> (Petroleum and natural gas processes)
As defined in §31-2, "petroleum and natural gas processes includes equipment used in processing crude and/or natural gas into refined products and includes catalytic cracking units, catalytic reforming units, and many others. There is no "new" affected equipment item at the facility.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
This subchapter limits new fuel-burning equipment with rated heat input greater than or equal to 50 MMBtu/hr to emissions of 0.20 lbs of NO_X per MMBtu, three-hour average for gas-fired equipment, 0.30 lbs/MMBtu for liquid-fired equipment, and 0.70 lbs/MMBtu for solid fuel-fired equipment. Most of the fuel-burning equipment at this facility is either too small or was constructed, rebuilt, or modified before the effective date of February 14, 1972 for "new" equipment. The following table indicates the compliance status of affected units.

Equipment	MMBtu/hr	Emission factor and source
#7 Boiler	150	0.20 lb/MMBtu, stack test of identical Boiler #9
#8 Boiler	150	0.20 lb/MMBtu, stack test of identical Boiler #9
#9 Boiler	150	0.20 lb/MMBtu, stack test
#10 Boiler	214.6	0.027 lb/MMBtu, manufacturer's data
#2 Plat PH-5	52	0.15 lb/MMBtu, manufacturer's data.
Coker B-1	60	0.09 lb/MMBtu, manufacturer's data, 0.06 lb/MMBtu per 7/22/92 stack test.
MEK H-101	81	0.15 lb/MMBtu, manufacturer's data.

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]
Affected processes under this subchapter include gray iron cupola, blast furnace, basic oxygen furnace, petroleum catalytic cracking unit, or petroleum catalytic reforming unit. Standards are based on whether the source is new or existing, where any source constructed or modified after July 1, 1972 is considered to be "new." The facility operates an existing petroleum catalytic reforming unit. Standards are set for existing units located in nonattainment or former nonattainment areas. Since Tulsa County has never been non-attainment for CO, the facility is not affected by this subchapter.

OAC 252:100-37 (Volatile Organic Materials) [Applicable]
37-4(a) Exempts VOCs with vapor pressure less than 1.5 psia from Sections 15, 16, 35, 36, 37, and 38. EUGs 20, 23, 24, and 25 qualify for this exemption.
37-15(a) Each VOC storage vessel with a capacity of more than 40,000 gallons shall be a pressure vessel capable of maintaining working pressures that prevent the loss of VOC or shall be equipped with one of three specified vapor control devices. Storage vessels subject to equipment standards in 40 CFR 60 (NSPS) Subparts K, Ka, or Kb are exempt from §§37-15(a) and (b) per §37-15(c). All storage vessels listed in EUGs 18, 19, 26, and 27 meet the requirements of 37-15(a). All other storage vessels that exceed 40,000 gallons contain VOCs less than 1.5 psia or are subject to NSPS Subparts K, Ka, or Kb.
37-15(b) Each VOC storage tank with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia must be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. All Holly tanks that are affected sources have bottom fill lines (EUGs 18, 19, 26, and 27). All other storage vessels that exceed 40,000 gallons contain VOCs less than 1.5 psia or are subject to NSPS Subparts K, Ka, or Kb.

The following list shows those vessels exempt under the 1.5 psia standard identified above.

EU	Point ID	BBL
20128	Tk6	1890
13559	Tk30	30,000
1356	Tk41	4200
13561	Tk50	1890
13562	Tk51	1890
13563	Tk155	54132
20129	Tk181	1000
6350	Tk189	55,000
6351	Tk190	55,000
13573	Tk277	7,000
6364	Tk279	7,000
13574	Tk281	7,000
13576	Tk283	7,000
6368	Tk312	7,000
6370	Tk315	7,000
6375	Tk401	55,000
13577	Tk402	55,000
6376	Tk403	53,578

EU	Point ID	BBL
13580	Tk421	55,000
13581	Tk422	55,000
3684	Tk434	50,821
13582	Tk433	55,000
13583	Tk444	55,000
13596	Tk582	4,061
NA	Tk696	1700
13588	Tk997	2,015
13589	Tk998	2,015
NA	Tk84	963
NA	Tk85	963
13588	Tk997	2015
13589	Tk998	2015
6406	Tk1002	55,000
NA	Tk1005	4,800
15950	Tk1012	5,000
16561	Tk1039	120,000
13569	Tk224	55,000

EU	Point ID	BBL
13573	Tk277	7,000
NA	Tk881	2,090
NA	Tk890	1,200
NA	Tk992	1,815
NA	Tk993	1,815
6324	Tk152	7,000
13565	Tk158	63,709
NA	Tk468	2,032
NA	Tk472	3,080
NA	Tk983	15,000
NA	Tk984	15,000
NA	Tk985	30,000
NA	Tk986	6,000
NA	Tk987	6,000
20127	Tk1	1698
Tk9	Tk9	7000
Tk10	Tk10	7000
Tk11	Tk11	7000
6334	Tk15	7000
6335	Tk16	7000
Tk23	Tk23	7000
Tk26	Tk26	55000
20130	Tk28	38000
6339	Tk29	55000
Tk33	Tk33	55000
Tk34	Tk34	55000
6342	Tk35	55000
6343	Tk36	55000
Tk38	Tk38	1890
Tk45	Tk45	4200
Tk46	Tk46	4200
Tk52	Tk52	1890
Tk53	Tk53	1890
Tk54	Tk54	1890
Tk62	Tk62	4200
Tk65	Tk65	1890
Tk66	Tk66	1890
Tk68	Tk68	1890
Tk69	Tk69	1890
Tk71	Tk71	5680
Tk72	Tk72	5680
Tk73	Tk73	5680
Tk74	Tk74	5680
Tk75	Tk75	1890

EU	Point ID	BBL
Tk76	Tk76	1890
Tk79	Tk79	1890
Tk80	Tk80	1890
Tk81	Tk81	1890
Tk83	Tk83	1890
Tk132	Tk132	1800
Tk133	Tk133	1800
Tk134	Tk134	7000
6344	Tk151	7000
13564	Tk156	55000
14307	Tk157	55000
15944	Tk159	55000
Tk192	Tk192	52300
15945	Tk193	52730
13567	Tk194	53100
Tk195	Tk195	55000
Tk196	Tk196	55000
6355	Tk215	50914
15946	Tk217	7000
13568	Tk218	7000
Tk223	Tk223	7000
Tk227	Tk227	7000
Tk228	Tk228	1890
Tk229	Tk229	1890
Tk232	Tk232	1890
Tk233	Tk233	1890
Tk234	Tk234	1890
Tk235	Tk235	1890
Tk236	Tk236	1890
Tk237	Tk237	1890
Tk240	Tk240	1500
Tk252	Tk252	7000
Tk264	Tk264	1890
Tk265	Tk265	1890
Tk266	Tk266	1890
Tk267	Tk267	1890
Tk271	Tk271	1890
6363	Tk272	1890
Tk273	Tk273	7000
Tk274	Tk274	7000
Tk275	Tk275	7000
Tk276	Tk276	7000
6364	Tk279	7000
6356	Tk280	7000

EU	Point ID	BBL
6366	Tk284	7000
Tk305	Tk305	7000
Tk317	Tk317	7000
Tk318	Tk318	7000
Tk319	Tk319	1890
Tk320	Tk320	1890
Tk321	Tk321	1890
Tk322	Tk322	1890
6371	Tk323	7000
Tk327	Tk327	1890
Tk328	Tk328	1890
Tk329	Tk329	1890
Tk331	Tk331	7000
Tk332	Tk332	7000
Tk335	Tk335	1890
Tk390	Tk390	7000
Tk391	Tk390	5000
Tk392	Tk392	5000
Tk393	Tk393	1000
Tk394	Tk394	1120
Tk396	Tk396	5940
Tk397	Tk397	5940
6373	Tk398	2600
6374	Tk399	2600
6377	Tk404	72273
6379	Tk407	71526
6380	Tk412	51773
6381	Tk413	50,859
6386	Tk445	74098
Tk471	Tk471	3780
Tk509	Tk509	4000
6389	Tk510	1890
6390	Tk511	1890
6391	Tk519	4000
Tk645	Tk645	1500
Tk646	Tk646	1500
Tk649	Tk649	1008
Tk650	Tk650	10000
Tk675	Tk675	1500
Tk691	Tk691	2400
Tk692	Tk692	2400
Tk693	Tk693	2400
Tk694	Tk694	2400
Tk700	Tk700	15000

EU	Point ID	BBL
13585	Tk701	15000
13584	Tk702	7000
6403	Tk799	1890
Tk800	Tk800	7000
15958	Tk801	15000
13586	Tk802	15000
15949	Tk803	15000
Tk807	Tk807	4200
Tk828	Tk828	30000
Tk829	Tk829	30000
Tk830	Tk830	30000
Tk831	Tk831	30000
Tk835	Tk835	2000
6404	Tk838	2000
Tk847	Tk847	2032
Tk848	Tk848	2032
Tk851	Tk851	2088
Tk852	Tk852	4025
Tk853	Tk853	4025
Tk854	Tk854	4025
Tk855	Tk855	4025
Tk856	Tk856	4025
Tk857	Tk857	2011
Tk861	Tk861	1000
Tk865	Tk865	1890
Tk867	Tk867	1675
13587	Tk870	5300
Tk875	Tk875	2090
Tk876	Tk876	3000
Tk877	Tk877	2090
Tk878	Tk878	2090
Tk879	Tk879	2090
Tk880	Tk880	3000
Tk882	Tk882	20000
Tk883	Tk883	1000
Tk884	Tk884	1000
Tk885	Tk885	1000
Tk886	Tk886	10492
Tk887	Tk887	19500
Tk888	Tk888	10492
Tk891	Tk891	1000
Tk893	Tk893	10500
Tk898	Tk898	2455
Tk913	Tk913	2090

EU	Point ID	BBL
Tk914	Tk914	2090
Tk916	Tk916	2090
Tk918	Tk918	30000
Tk921	Tk921	2094
Tk922	Tk922	3058
Tk923	Tk923	2084
Tk924	Tk924	4455
Tk925	Tk925	4455
Tk926	Tk926	1313
Tk927	Tk927	1313
Tk928	Tk928	4455
Tk929	Tk929	4455
Tk930	Tk930	1313
Tk931	Tk931	1313
Tk932	Tk932	3058
Tk933	Tk933	1000

EU	Point ID	BBL
Tk934	Tk934	1000
Tk935	Tk935	1000
Tk936	Tk936	1000
Tk937	Tk937	1000
Tk938	Tk938	1000
Tk939	Tk939	1000
Tk940	Tk940	1000
Tk941	Tk941	1000
Tk942	Tk942	1000
Tk943	Tk943	1000
Tk944	Tk944	1000
Tk955	Tk955	1000
TkAGT1	TkAGT1	2000
TkAGT2	TkAGT2	1000
TkAGT3	TkAGT3	1000
TkAGT4	TkAGT4	2000

The following list shows those vessels exempt under the NSPS standard identified above.

EU	Point ID	Nominal Capacity (BBLs)
6338	Tk25	55,000
13594	Tk1061	80,000
20126	Tk1070	5,377
NA	Tk1080	3,200
6402	Tk782	15,000
13591	Tk583	4,800

37-16(a) (Loading facilities with throughput greater than 40,000 gallons/day.) 37-16(b) (Loading facilities with throughput equal to or less than 40,000 gallons/day.) EUG 13 is subject to 40 CFR Part 63 Subpart CC, which subsumes the requirements of NSPS Subpart XX and NESHAP Subpart R, and is therefore exempt from §§37-16(a) and (b) per §37-16(c). The following loading racks are not subject to OAC 252:100-37-16 because the units do not load VOC containing material, per §37-4(a).

EU	Equipment Point ID	Installed Date
NA	Black Oil Loading Rack	1937
NA	Extract Truck Loading Rack	1993
NA	Extract Rail Loading Rack	1930
NA	Wax Truck Loading Rack	1979
NA	Wax Rail Loading Rack	1917
NA	LOB Rail Loading Rack	1967
NA	LOB Truck Loading Rack	1978
NA	Resid Truck Loading Rack	1962

EU	Equipment Point ID	Installed Date
NA	Diesel Rail Loading Rack	1986
NA	Coke Truck Loading Area	1991

Section 37-36 requires fuel-burning equipment to be operated and maintained so as to minimize VOC emissions. Temperature and available air must be sufficient to provide essentially complete combustion. Refinery fuel combustion devices are designed to provide essentially complete combustion of organic materials.

Section 37-37 regulates water separators that receive water containing more than 200 gallons per day of VOC. All oil/water separators listed in EUG 35 receiving VOC material with vapor pressure greater than 1.5 psia are sealed per 37-37(1). Separators built since 7/1/72 are either sealed irrespective of the 200-gpd trigger or do not process 200 gpd organics per records on file.

OAC 252:100-39 (VOC in Non-Attainment and Former Nonattainment Areas) [Applicable]

Section 39-15 (Petroleum Refinery Equipment Leaks) EPA test Method 21 is specified for detecting equipment leaks. VOC with vapor pressure less than 0.0435 is exempt. Components covered by this section include, but are not limited to, pumping seals, compressor seals, seal oil degassing vents, pipeline valves, flanges and other connections, pressure relief devices, process drains, and open-ended pipes. All such components are tested in a monitoring program per 15(f); actions and repairs are conducted per 15(c); records are kept per 15(g); quarterly reports are made per 15(h); and monitoring logs are retained on-site for least two years.

Section 39-16 (Petroleum refinery process unit turnaround) Vented organic material must either be controlled per 39-16(b)(1) & (2) or exempted per 39-16(b)(4). Requirements for contents of the 15-day notification are listed in 39-16(b)(3). Holly has provided the appropriate notices for past turnarounds and is in compliance based on standard unit turnaround practices that meet requirements.

Section 39-17 (Petroleum refinery vacuum producing system) The vacuum system at the CDU vacuum towers, T-2 and T-3, employs steam ejectors, surface condensers, and a mechanical vacuum pump to deliver vacuum gases to the CDU H-2 heater. If the vacuum pump fails, the third stage jet system is used to deliver gases to H-2.

The vacuum system at the LEU T-201 vacuum tower employs ejectors and surface condensers. The surface condenser gases are in turn ejected with natural gas into dedicated burners in the LEU H-102 heater. Both vacuum gas streams are disposed by direct combustion into the firebox of a large heater. Flowing this material to the unit heater obviates a requirement that the pilot flame be monitored. Maintenance records on the systems are being kept.

Section 39-18 (Petroleum refinery effluent water separators) Separators listed in EUG 35 receiving VOC material are sealed and are in compliance by separator design.

Section 39-30 **(**Petroleum liquid storage in vessels with external floating roofs) Storage tank 874 listed in EUG 27 is subject to 39-30(c). Storage vessels listed in EUG 19 are exempt per 39-30(b)(4) because they are subject to 40 CFR Part 63 Subpart CC. Storage vessels listed in EUG 22 are exempt per 39-30(b)(3) because they are subject to 40 CFR Part 60 Subpart Kb. Storage vessels listed in EUG 20, 23, 24, and 25 are exempt per 39-30(b)(2)(C) because they contain liquids with true vapor pressure less than 1.5 psia.

Section 39-40 (Cutback asphalt (paving))

Cutback liquefied asphalt cannot be applied or prepared in the facility without prior written consent of the Division Director.

Section 39-41 (Storage, loading and transport/delivery of VOCs)

Holly stores and loads gasoline delivery trucks, but does not deliver gasoline. Holly is subject to the storage and loading part of this section of the subchapter.
Subsection 39-41(a) Storage of VOCs in vessels with storage capacities greater than 40,000 gallons. Each vessel with a capacity greater than 40,000 gallons storing VOC with a true vapor pressure that exceeds 1.50 psia must have either a floating internal or external roof that meets the requirement of this section. Tank inspections are documented electronically on the Refinery Tanks Database. Electronic documentation records the date of the inspection, any defects noted, and the initials of the inspector. Storage tanks in EUG 18, 19, 21, 22, 26, and 27 are subject. Storage tanks in EUG 20, 23, 24, and 25 are exempt because the VOC vapor pressure is less than 1.5 psia.
Subsection 39-41(b) Storage of VOCs in vessels with storage capacities of 400-40,000 gallons. Each vessel with this capacity and storing a VOC with a vapor pressure greater than 1.5 psia is equipped with a bottom fill line.
Subsection 39-41(c) Loading of VOCs. The truck terminal of EUG 13 meets the design requirements of this subsection (-39-41(c)(1)), and is in compliance based on the original efficiency test.
Subsection 39-41(d) Transport/delivery. No delivery vessel incapable of accepting displaced vapors and designated as vapor tight is allowed to load at the facility's loading terminal.
Subsection 39-41(e) Additional requirements for Tulsa County. Only Paragraphs 3 and 4 apply.
§39-41(e)(3) (Loading of VOCs) requires that the stationary loading facility be checked annually using EPA Method 21. Leaks greater than 5,000 ppmv shall be repaired within 15 days. The facility appears to be in compliance, based on current leak test records.
§39-41(e)(4) (Transport/delivery vessel requirement) requires that transport vessels be maintained vapor tight and must be capable of receiving and storing vapors for ultimate delivery to a vapor recovery/disposal system. Any defect that impairs vapor tightness must be repaired within five days. Certification of vapor tightness and of repairs must be provided and no vessel shall be loaded without demonstrating the proper certification. DEQ may perform spot checks of vapor tightness and may require owner/operators to make necessary repairs. This facility and the transports loading there have been in compliance.
Section 39-42 (Metal cleaning) contains requirements for cold cleaning, vapor degreasing, and conveyorized degreasing. The facility has no vapor or conveyorized units, so only §39-42(a) applies. All equipment shall have a cover or door that can be easily operated with one hand, shall provide an internal drain board that will allow lid closure if practical or provide an external drainage facility, shall have an attached permanent, conspicuous label summarizing the operating requirements of OAC 252:100-39-42(a)(2). Control requirements are identified in §39-42(a)(3) for those solvents with vapor pressure greater than 0.6 psi. The solvent used in all of the metal cleaners is ACTREL PC 95 Cleaner, a very low vapor pressure (0.00038 psia @ 68 deg F) petroleum hydrocarbon manufactured by EXXON Chemical Americas, so none of the listed controls is required. Facility will keep on-site records of service and maintenance. Emissions from units are so low as to be negligible.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
Part 5 of OAC 252:100-41 was superseded by this subchapter. Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained unless a modification is approved by the Director. Since no Area of

Concern (AOC) has been designated anywhere in the state, there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

The following Oklahoma Air Pollution Control Rules are not applicable to this facility:

OAC 252:100-11	Alternative Emissions Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not in source category
OAC 252:100-24	Grain Elevators	not in source category
OAC 252:100-35	Control of CO	not in source category
OAC 252:100-39-43	Graphic Arts	not in source category
OAC 252:100-39-44	Tire Mfg.	not in source category
OAC 252:100-39-45	Dry Cleaning	not in source category
OAC 252:100-39-46	Parts Coating	not in source category
OAC 252:100-39-47	Aerospace Coating	not in source category
OAC 252:100-39-49	Fiberglass Mfg.	not in source category
OAC 252:100-47	MSW Landfills	not in source category

SECTION VI. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
Holly is a major PSD source since it is on the list of 26 source categories and has emissions of at least one criteria pollutant that exceeds 100 TPY. This modification resulted in a significant emission increase for CO_{2e} and a significant net emission increase for CO_{2e}. The PSD review is in Section IV. Any future increases of emissions must be evaluated for PSD if they exceed a

significance level (40 TPY NO_X, 100 TPY CO, 40 TPY VOC, 40 TPY SO_2, 25 TPY PM_{10}, and 75K TPY CO_2e).

NSPS, 40 CFR Part 60 [Subparts A, Db, J, Ja, K, Ka, Kb, GGG, and GGGa Applicable]
The following paragraphs are general in nature, with some reference to specific facilities. The Specific Conditions contain specific requirements under NSPS for all affected facilities.

Subpart A specifies general control device requirements for control devices used to comply with applicable subparts. EUG 11 is in compliance with 60.18 and the corresponding regulatory section 60.485(g) by physical design and per the alternate test methods approved by DEQ and discussed below. Records kept on-site to meet monitoring and recordkeeping requirements of 60.486(d)(1), (2), and (3) are also discussed below. The facility is in compliance with 40 CFR 60.7 (b) as to Startup/Shutdown/Malfunction records, per current records.

The Lube Unit Flare was built in 1976 and serves the release combustion needs of just the Lube Extraction Unit of the refinery. The date of construction makes this a potentially affected source under 40 CFR 60 Subpart J. However, this flare is not designed to burn refinery fuel gas except during instances of emergency fuel gas release from PRV's in the Lube Extraction Unit and hence has no applicable requirements under Subpart J. The flare is used as a control device under Subpart GGG. Subpart GGG refers to 60.482-10(d) of NSPS Subpart VV, which refers in turn to 60.18 in NSPS Subpart A for requirements applicable to the flare. The requirements at 60.18(c)(1)-(4) for no visible emissions stipulate Reference Methods for visible emissions, a pilot flame sensor (a physical requirement that the Lube Flare has) and a gas heat value demonstration. Holly was approved for alternative methods for the visible emissions and heat value demonstrations, which is discussed separately below. Sections 60.18(d) and (e) specify monitoring per GGG and continuous flare operation when GGG vapors are going to it. Physical design of the flare system satisfies the operational requirement. Monitoring per GGG is specified at 60.486(d)(1)-(5). Items (4) and (5) of this last citation are redundant to the startup/shutdown/malfunction records required by the General Provisions at 60.7(b) and this is handled by saying that compliance with 60.7(b) satisfies items (4) and (5). Monitoring under GGG thus reduces to the recordkeeping specifics at 60.486(d)(1)-(3). Item (1) requires Schematics, Design Specifications, and P&IDs to be readily available, which the facility provides. Item (2) requires dates and description records of any changes to the system, which are available; and item (3) requires a description of what parameters will be monitored (to assure that the system is operated and maintained in conformance with their design as stated at 60.482-10(e)). The facility takes the position that the most efficient parameters to be monitored are the presence of a pilot flame and the absence of smoke during flaring. These parameters are part of the record required and kept under 60.7(b), General Provision, any exception to which the facility is obligated to report immediately to the DEQ per OAC 252:100-9.

Alternative Test Methods for Flares Approved
In a letter dated December 20, 1996, S.K. Martin of Sunoco applied to Mr. Garry Keele of ODEQ for alternate test approvals for determination of smokeless operation, exit velocity of the flare, and BTU value of the gas to the flare. Sunoco (Holly) proposed that because of the impossibility of observing and testing what normally occurs only during upsets, Sunoco (Holly) would document calculations based on records under 60.486(d) for: 1) the design specification

of the flare to show it will operate smokeless; 2) the calculated maximum exit velocity of the flare based on the design criteria; and 3) the calculated net heating value of the gas relieved to the flare based on the simulated composition of the gas. A letter from S.K. Martin to Garry Keele, dated January 2, 1997, documents a conversation on that same day in which ODEQ approved Sunoco's (Holly's) proposal. Copies of the test results were reviewed by DEQ Compliance during a 2004 inspection, and are currently on file at Holly.

The LEU Flare would become subject to Subpart Ja as it was initially published. The definition of modification for flares § 60.100a(c) has been stayed. At this time the permit will contain a requirement for the affected emission unit to comply with the applicable requirements of this subpart when they become final.

PLAT
This flare is used to control Group 1 process control vent gases under 40 CFR 63, Subpart CC, a regulatory requirement presented under EUG 14. As such this flare has requirements under Subpart CC as a control device, and under 40 CFR 63 General Provisions for a flare used as a control device and as to startup/shutdown/malfunction records.

Subpart D, (Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971)
This is not applicable because there are no fossil-fuel-fired steam generators with a heat input greater than 250 MMBtu/hr.

Subpart Da (Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978)
This is not an applicable requirement because there are no electric utility steam generating units.

Subpart Db (Industrial-Commercial-Institutional Steam Generating Units for Which Construction Is Commenced After June 19, 1984)
The following units were constructed or modified prior to the effective date of the standard.

EU	Point ID	Construction Date
105A	#1 Boiler	1948
105B	#2 Boiler	1948
106A	#3 Boiler	1954
106B	#4 Boiler	1957

The new Boiler #10 will be subject to NSPS Subpart Db.

Since Boiler #10 does not burn coal or No. 2 fuel oil, it is only subject to Sections 60.44b, 60.46b, 60.48b, and 60.49b of this subpart (standards of Subpart Db for SO_2 and PM do not apply to gas-fueled boilers). Requirements include:

- Compliance testing for particulate matter and nitrogen oxides (40 CFR 60.46b). The emission standard for oxides of nitrogen is 0.2 lb/MMBTU per §60.44b(a), including periods of start-up, shutdown and malfunction (§60.44b(h). Compliance with the NO_X standard is to be demonstrated on a rolling 30-day basis, except that the initial performance test shall demonstrate compliance on a 24-hour basis and any subsequent performance tests shall demonstrate compliance on a 3-hour basis (§60.44b(i, j)).

- Emissions monitoring for nitrogen oxides (40 CFR 60.48b). The applicant will install a continuous emission monitor (CEM) to monitor NOx on boiler #10.
- Reporting and recordkeeping (40 CFR 60.49b). HRMT will record natural gas and refinery gas usage and CEMs data.

Subpart Dc (Small Industrial-Commercial-Institutional Steam Generating Units for Which Construction Is Commenced After June 9, 1989)
There are no applicable units constructed or modified after the effective date of the standard.

Subpart J (Petroleum Refineries)
#2 Platformer PH-5 & PH-6 Heaters operate under an Alternative Monitoring Plan for NSPS Subpart J Fuel Gas approved May 31, 2001. However, the PH-6 heater is not subject to NSPS J because it has not been constructed/modified/reconstructed since the effective date. A request was approved in 2004 to allow boilers 7, 8, and 9 to burn absorber tower offgas, so the boilers are now subject to NSPS J and follow the same alternative monitoring plan as heaters PH-5 and PH-6.

The following units are not subject to NSPS Subpart J because they were constructed prior to the applicability date of June 11, 1973.

EU	Point ID	Construction Date
105A	#1 Boiler	1948
105B	#2 Boiler	1948
106A	#3 Boiler	1954
106B	#4 Boiler	1957
201N	CDU H-1,N,#7	1961
201S	CDU H-1,S,#8	1961
202	CDU H-2	1961 (1)
203	CDU H-3	1961 (1)
206	Unifiner H-2	1957
207	Unifiner H-3	1957
209	#2 Plat PH-1/2	1957
210	#2 Plat PH-3	1957
211	#2 Plat PH-4	1957
213	#2 Plat PH-6	1957
214	#2 Plat PH-7	1971
238	PDA B-30	1956
240	PDA B-40	1962
242	LEU H101	1963
243N	LEU H102	1963[1]
243S	LEU H102	1963[1]
244	LEU H-201	1963
246	MEK H-2	1959

> (1) Low NO_X burners were installed in units CDU H-2 and H-3 and LEU H-102 in 1989. As stated in the construction permit (T89-37; August 11, 1989), this installation did not qualify as a modification or reconstruction, and thus, the units remain exempted from this rule.

The following units, although constructed or modified after the applicability date, are not subject to NSPS Subpart J because, as specified in the construction permit, the units will not burn refinery process gas.

EU	Point ID	Construction Date
224	Coker H-3	1995 (Permit 94-404-0 M-1)
225	Coker B-1	1992 (Permit T91-110)
245	MEK H-101	1977 (Permit 77-006-0)

The LEU flare, EU-269 (EUG-11) is not subject to NSPS Subpart J because it does not burn refinery fuel gas except during instances of emergency fuel gas release from PRVs in the Lube Extraction Unit.

Subpart Ja, Petroleum Refineries. On June 24, 2008, EPA promulgated standards for new, modified, or reconstructed affected facilities at petroleum refineries. The provisions of this subpart apply to the following affected facilities in petroleum refineries: fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices, including flares and process heaters, and sulfur recovery plants. Only those affected facilities that begin construction, modification, or reconstruction after May 14, 2007, are subject to this subpart.

On July 28, 2008, EPA promulgated a “stay of the effective date” of the standards for new, modified, or reconstructed affected facilities at petroleum refineries until September 26, 2008. On September 26, 2008, EPA promulgated a “reconsideration and stay of effective date” for specific provisions in the newly promulgated standards. The effective date for these specific provisions was stayed to December 25, 2008. On December 22, 2008, the EPA promulgated an interim final determination to extend the stay for 60 days until February 24, 2009, until the concurrent direct final action and parallel proposal becomes effective which will stay these issues until they are resolved or until further notice. The notice stayed the following:

1. The definition of modification for flares § 60.100a(c);
2. The definition of ‘‘flare’’ in § 60.101a;
3. The fuel gas combustion device sulfur limits of § 60.102a(g);
4. The sulfur monitoring for flares of § 60.107a(d) and flow monitoring for flares of § 60.107a(e).

Fuel Gas Combustion Devices

Fuel gas combustion device means any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid. All of the flares were constructed and have not been reconstructed or modified after May 14, 2007, except for the LEU Flare which may be modified, pending the final "definition of modification for flares."

Even though the standard has been stayed, Subpart Ja established a fuel gas H_2S limitation for all fuel gas combustion devices which commence construction, reconstruction, or modification after May 14, 2007, of 162 ppmv determined hourly on a 3-hour rolling average basis and 60 ppmv determined daily on a 365 successive calendar day rolling average basis. Subpart Ja requires the fuel gas H_2S concentration to be continuously monitored and recorded. The proposed and stayed provision of this subpart also establish a flow limitation of 250,000 standard cubic feet per day (SCFD) based on a 30-day rolling average, except for process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions.

Whatever the final compliance dates and limits that are finally established by this subpart, the LEU Flare will have to comply with them. The flare listed in the following table is considered an affected facility and will be subject to the fuel gas sulfur content limitation established. The boiler listed in the following table is considered an affected facility and is subject to the fuel gas sulfur content limitation.

EU	**CD**	**Description**	**Mod. Date**
269	1976	LEU Flare	2010
TBD	TBD	Boiler #10	2012

At this time the permit will contain a requirement for the LEU Flare to comply with the applicable requirements of this subpart when they become final. The permit contains the applicable requirements for Boiler #10.

Subpart K (Petroleum Liquids) applies to volatile organic liquids storage vessels for which construction, reconstruction, or modification commenced after June 11, 1973, or before May 19, 1978, which have a capacity of 40,000 gallons or more, and which do not contain organic materials specifically exempted. Those materials specifically exempted include diesel, jet fuel, kerosene, and residual fuel oils. Per 60.112, controls are required if storing material above a true vapor pressure (TVP) of 1.5 psia. Records of stored material stated in 60.113(a) are not required if the stored material is below a Reid vapor pressure (RVP) of 1.0 psia, but are required regardless of RVP if TVP is greater than 1.0 psia, per 60.113(d)(1). Tanks listed in EUG 25 are exempt from recordkeeping because material stored is below 1.0 psia RVP and TVP.

Subpart Ka (Petroleum Liquids) applies to volatile organic liquids storage vessels for which construction, reconstruction, or modification commenced after May 18, 1978, but before July 23, 1984, which have a capacity of 40,000 gallons or more, and which do not contain organic materials specifically exempted. Those materials specifically exempted include diesel, kerosene, and residual fuel oils. Per 60.112(a) controls are not required if stored material is below 1.5 RVP. Records of stored material per 60.115(a) are required if RVP is above 1.0, but not if below 1.0 per 60.115(d)(1). Tanks in EUG 24 are exempt from recordkeeping.

Subpart Kb (VOL Storage Vessels) applies to volatile organic liquids storage vessels for which construction, reconstruction, or modification commenced after July 23, 1984, and which have a capacity of 75 cubic meters (m^3) or more. Tanks with capacity greater than or equal to 151 m^3 and storing VOL with TVP less than 3.5 kPa (≈ 0.5 psia) are exempt from Kb, as are tanks with capacity greater than or equal to 75 m^3 and less than 151 m^3 that store VOL with TVP less than 15.0 kPa (≈ 2.2 psia). Tanks with capacity greater than or equal to 151 m^3 and storing VOL with TVP equal to or greater than 5.2 kPa (≈ 0.75 psia) but less than 76.6 kPa (≈ 11.1 psia) are required to have the controls described in §60.112b(a). Tanks with capacity greater than or equal to 75 m^3 and less than 151 m^3 and storing VOL with TVP equal to or greater than 27.6 kPa (≈ 4.0 psia) but less than 76.6 kPa are also required to have the controls described in §60.112b(a). Tanks with TVP greater than 76.6 kPa must install the closed systems described in §60.112b(b). Tanks subject to the controls of §60.112b are subject to the testing and inspection requirements of §60.113b and the reporting and recordkeeping requirements of §60.115b. All tanks, regardless of controls, are subject to the monitoring requirements of §60.116b. Compliance is per monitoring specified at 60.113(b), and records and reporting as specified at sections 60.115(b) and 60.116(b). Tanks in EUGs 21, 22, and 23 are affected facilities under Subpart Kb. Tank inspections are documented electronically on the Refinery Tanks Database. Electronic documentation records the date of the inspection, any defects noted, and the initials of the inspector.

The following petroleum/volatile organic liquid storage tanks are not subject to NSPS Subparts K, Ka, or Kb because the tanks were constructed or modified prior to the applicability dates. Other tanks may be exempt based on the vapor pressure of the VOL stored, but those tanks are not listed here.

EU	Tank #	Nominal BBL	Year
6336	21	33,178	1916
6337	22	33,284	1916
6340	31	35,411	1940
6346	153	47,858	1917
6359	242	48,654	1917
6360	244	55,000	1917
6387	473	1,500	1979
13579	411	55,000	1922
6341	413	50,859	1922
6382	423	51,163	1923
1591	432	74,529	1953
6383	433	50,910	1923
6385	435	74,132	1953
1359	502	7,000	1965
6392	742	10,000	1948
6393	747	10,000	1948
5397	751	10,000	1949
6367	307	10,000	1946
6398	752	10,000	1949
6396	750	10,000	1972
6399	755	10,000	1950
6401	779	10,000	1953

EU	Tank #	Nominal BBL	Year
6369	314	7,000	1922
20128	6	1890	1916
6333	13	55,000	1916
13559	30	30,000	1917
1356	41	4200	1929
13561	50	1890	1917
13562	51	1890	1917
13563	155	54132	1917
20129	181	1000	1928
6347	185	55,000	1922
6348	186	55,000	1922
6349	187	55,000	1922
13592	188	55,000	1922
6350	189	55,000	1922
6351	190	55,000	1922
13570	258	1,890	1917
13571	259	1,890	1917
13573	277	7,000	1917
6364	279	7,000	1947
13574	281	7,000	1969
13575	282	7,000	1917
13576	283	7,000	1917

EU	Tank #	Nominal BBL	Year
6368	312	7,000	1922
6370	315	7,000	1917
6375	401	55,000	1922
13577	402	55,000	1922
6376	403	53,578	1922
13580	421	55,000	1923
13581	422	55,000	1922
3684	434	50,821	1923
13582	433	55,000	1923
13583	444	55,000	1923
13594	546	1,700	1943
13596	582	4,061	1936
NA	696	1700	1948
6405	874	121,275	1965
6333	13	55,000	1917
8347	185	55,000	1922
6348	186	55,000	1922
6349	187	55,000	1922
13592	188	55,000	1922
6405	874	121,275	1965
20127	1	1,698	1916
Tk9	9	7,000	1968
Tk10	10	7,000	1916
Tk11	11	7,000	1916
6334	15	7,000	1916
6335	16	7,000	1916
Tk23	23	7,000	1916
Tk26	26	55,000	1916
20130	28	38,000	1964
6339	29	55,000	1964
Tk33	33	55,000	1917
Tk34	34	55,000	1917
6342	35	55,000	1917
6343	36	55,000	1917
Tk38	38	1,890	1928
Tk45	45	4,200	1917
Tk46	46	4,200	1917
Tk52	52	1,890	1917
Tk53	53	1,890	1917
Tk54	54	1,890	1917
Tk62	62	4,200	1917
Tk65	65	1,890	1917
Tk66	66	1,890	1917
Tk68	68	1,890	1917

EU	Tank #	Nominal BBL	Year
Tk69	69	1,890	1917
Tk71	71	5,680	1917
Tk72	72	5,680	1917
Tk73	73	5,680	1917
Tk74	74	5,680	1917
Tk75	75	1,890	1917
Tk76	76	1,890	1917
Tk79	79	1,890	1917
Tk80	80	1,890	1917
Tk81	81	1,890	1917
Tk83	83	1,890	1917
Tk132	132	1,800	1922
Tk133	133	1,800	1922
Tk134	134	7,000	1922
6344	151	7,000	1917
13564	156	55,000	1917
14307	157	55,000	1924
15944	159	55,000	1925
6352	191	55,000	1922
Tk192	192	52,300	1943
15945	193	52,730	1917
13567	194	53,100	1966
Tk195	195	55,000	1917
Tk196	196	55,000	1916
6355	215	50,914	1917
15946	217	7,000	1917
13568	218	7,000	1968
Tk223	223	7,000	1917
Tk227	227	7,000	1917
Tk228	228	1,890	1917
Tk229	229	1,890	1917
Tk232	232	1,890	1917
Tk233	233	1,890	1917
Tk234	234	1,890	1917
Tk235	235	1,890	1917
Tk236	236	1,890	1917
Tk237	237	1,890	1917
Tk240	240	1,500	1917
Tk252	252	7,000	1966
Tk264	264	1,890	1917
Tk265	265	1,890	1917
Tk266	266	1,890	1917
Tk267	267	1,890	1917
Tk271	271	1,890	1917

EU	Tank #	Nominal BBL	Year	EU	Tank #	Nominal BBL	Year
6363	272	1,890	1917	Tk650	650	10,000	1940
Tk273	273	7,000	1917	Tk675	675	1,500	1942
Tk274	274	7,000	1929	Tk691	691	2,400	1942
Tk275	275	7,000	1963	Tk692	692	2,400	1942
Tk276	276	7,000	1917	Tk693	693	2,400	1942
6364	279	7,000	1947	Tk694	694	2,400	1942
6356	280	7,000	1947	Tk700	700	15,000	1942
6366	284	7,000	1966	13585	701	15,000	1942
Tk305	305	7,000	1929	13584	702	7,000	1942
Tk317	317	7,000	1917	6400	775	55,000	1916
Tk318	318	7,000	1917	6403	799	1,890	1956
Tk319	319	1,890	1917	Tk800	800	7,000	1956
Tk320	320	1,890	1917	15958	801	15,000	1956
Tk321	321	1,890	1917	13586	802	15,000	1956
Tk322	322	1,890	1917	15949	803	15,000	1956
6371	323	7,000	1917	Tk807	807	4,200	1958
Tk327	327	1,890	1917	Tk828	828	30,000	1960
Tk328	328	1,890	1917	Tk829	829	30,000	1960
Tk329	329	1,890	1917	Tk830	830	30,000	1960
Tk331	331	7,000	1917	Tk831	831	30,000	1960
Tk332	332	7,000	1917	Tk835	835	2,000	1960
Tk335	335	1,890	1967	6404	838	2,000	1960
Tk390	390	7,000	1929	Tk847	847	2,032	1961
Tk391	390	5,000	1929	Tk848	848	2,032	1961
Tk392	392	5,000	1929	Tk851	851	2,088	1961
Tk393	393	1,000	1930	Tk852	852	4,025	1962
Tk394	394	1,120	1930	Tk853	853	4,025	1962
Tk396	396	5,940	1963	Tk854	854	4,025	1962
Tk397	397	5,940	1963	Tk855	855	4,025	1962
6373	398	2,600	1928	Tk856	856	4,025	1962
6374	399	2,600	1928	Tk857	857	2,011	1962
6377	404	72,273	1938	Tk861	861	1,000	1968
6379	407	71,526	1948	Tk865	865	1,890	1963
6380	412	51,773	1922	Tk867	867	1,675	1964
6381	413	50,859	1922	13587	870	5,300	1963
6386	445	74,098	1953	Tk875	875	2,090	1966
Tk471	471	3,780	1917	Tk876	876	3,000	1966
Tk509	509	4,000	1969	Tk877	877	2,090	1966
6389	510	1,890	1966	Tk878	878	2,090	1966
6390	511	1,890	1966	Tk879	879	2,090	1966
6391	519	4,000	1932	Tk880	880	3,000	1966
Tk645	645	1,500	1938	Tk882	882	20,000	1967
Tk646	646	1,500	1936	Tk883	883	1,000	1967
Tk649	649	1,008	1937	Tk884	884	1,000	1967

EU	Tank #	Nominal BBL	Year
Tk885	885	1,000	1967
Tk886	886	10,492	1967
Tk887	887	19,500	1967
Tk888	888	10,492	1967
Tk891	891	1,000	1968
Tk893	893	10,500	1972
Tk898	898	2,455	1917
Tk913	913	2,090	1917
Tk914	914	2,090	1917
Tk916	916	2,090	1917
Tk918	918	30,000	1972
Tk921	921	2,094	1966
Tk922	922	3,058	1966
Tk923	923	2,084	1966
Tk924	924	4,455	1966
Tk925	925	4,455	1966
Tk926	926	1,313	1966
Tk927	927	1,313	1966
Tk928	928	4,455	1966
Tk929	929	4,455	1966
Tk930	930	1,313	1966
Tk931	931	1,313	1966
Tk932	932	3,058	1966
Tk933	933	1,000	1966
Tk934	934	1,000	1966
Tk935	935	1,000	1966
Tk936	936	1,000	1966
Tk937	937	1,000	1966
Tk938	938	1,000	1966
Tk939	939	1,000	1966
Tk940	940	1,000	1966
Tk941	941	1,000	1966
Tk942	942	1,000	1966
Tk943	943	1,000	1966
Tk944	944	1,000	1966
Tk955	955	1,000	1966
TkAGT1	AGT1	2,000	1922
TkAGT2	AGT2	1,000	1922
TkAGT3	AGT3	1,000	1922
TkAGT4	AGT4	2,000	1922

Subpart GG (Stationary Gas Turbines)
There are no stationary gas turbines on-site.

Subpart UU (Asphalt Processing and Asphalt Roofing) Per 40 CFR 60.470, affected facilities include asphalt storage tanks and blowing stills at refineries, for which construction or modification commenced after May 26, 1981. There are no active asphalt operations on-site.

Subpart VV (Equipment Leaks of VOC in SOCMI) Although the refinery is not an affected facility, the refinery MACT (40 CFR 63 Subpart CC) makes extensive reference to this NSPS subpart.

Subpart VVa, Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry (SOMCI). This subpart affects equipment constructed, reconstructed or modified after November 7, 2006. NSPS, Subpart GGGa requires equipment constructed, reconstructed or modified after November 7, 2006 in VOC service to comply with paragraphs §§ 60.482-1a through 60.482-10a, 60.484a, 60.485a, 60.486a, and 60.487a except as provided in § 60.593a. Most of the equipment at the refinery was constructed prior to November 7, 2007 and is covered under NSPS, Subpart GGG or NESHAP Subpart CC. The equipment in the relief system modification will not be subject to NSPS, Subpart GGGa and will not have to comply with the requirements of this subpart.

Subpart XX (Bulk Gasoline Terminals) Per 40 CFR 60.500, affected facilities include all loading racks at a bulk gasoline terminal, for which construction or modification commenced after December 17, 1980. Further, any replacement of components commenced before August 18, 1983, in order to comply with emission standards adopted by the Oklahoma State Department of Health or the Tulsa City/County Health Department are not to be considered a reconstruction under 40 CFR 60.15. The gasoline loading racks were constructed and/or modified prior to the effective dates described, and are not affected facilities.

Subpart GGG (Equipment Leaks of VOC in Petroleum Refineries) affects each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service which commenced construction or modification after January 4, 1984, and which is located within a process unit in a petroleum refinery. Subpart GGG requires the leak detection, repair, and documentation procedures of NSPS Subpart VV. Compressors in hydrogen service (defined as serving streams more than 50% by volume hydrogen) are exempt from all requirements other than demonstrating that a stream can never be reasonably expected to contain less than 50% by volume hydrogen. Those pressure-relief devices vented to a control device (flare) are exempted from periodic monitoring requirements. Equipment in EUG 7 is subject to this subpart and compliance records are maintained on-site in an electronic database. Equipment in EUG 8 is subject to NESHAP MACT Subpart CC, and equipment in EUG 9 is subject to OAC 252:100-39-15.

All Leak Detection and Repair (LDAR) reporting required by 40 CFR 60, Subpart GGG (semi-annual), and 40 CFR 63, Subpart CC (semi-annual) has been consolidated to simplify overlapping requirements, based on discretion granted to the state authorities by EPA. All LDAR reporting is included in the MACT Semi-annual report covering all monitoring required from January 1st through June 30^{th} and July 1st through December 31st. Reports are due 60 days after the end of each six month period per 40 CFR 63.654(g).

Subpart GGGa, Equipment Leaks of VOC in Petroleum Refineries. This subpart affects each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service at a process unit, which commenced construction or modification after November 7, 2006, and which is located at a petroleum refinery. This subpart defines "process unit" as "components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates: a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product." Subpart GGGa requires the leak detection, repair, and documentation procedures of NSPS, Subpart VVa. All affected equipment which commenced construction or modification after November 7, 2006, in VOC service and not in HAP service is subject to this subpart. In accordance with § 63.640(p)(2), equipment leaks that are also subject to the provisions of 40 CFR part 60, Subpart GGGa, are required to comply only with the provisions specified in 40 CFR part 60, Subpart GGGa. The group of all the equipment (defined in §60.591a) within a process unit is an affected facility. Any new piping components added to accommodate the new boiler will be subject to 40 CFR 60 Subpart GGGa and will be included in the refinery's LDAR program.

Subpart QQQ (VOC Emissions from Petroleum Refinery Wastewater Systems) applies to individual drain systems, oil-water separators, and aggregate facilities located in petroleum refineries and for which construction, reconstruction, or modification commenced after May 4, 1987. All wastewater systems were constructed or modified prior to the effective date of the standard.

NESHAP, 40 CFR Part 61 [Subparts M and FF Applicable]

Subpart J (Equipment Leaks {Fugitive Emission Sources} of Benzene)
Affected sources are equipment items in "benzene service," which is defined to mean that they contact a stream with at least 10% benzene content by weight. The facility has no items in benzene service.

Subpart M (Asbestos)
Molded or wet-applied friable asbestos insulation installation or reinstallation is prohibited per 61.148. The most likely activity that might be affected is the renovation or demolition of structures or equipment containing asbestos. Rules concerning such activities are found in §§60.145 and 60.150.

Subpart V (Equipment Leaks {Fugitive Emission Sources})
Affected sources are equipment items in "VHAP service," which is defined to mean that they contact a stream with at least 10% of a volatile HAP content by weight. The facility has no items in VHAP service.

Subpart Y (Benzene Emissions from Benzene Storage Vessels)
Affected sources are vessels storing benzene. The facility has no benzene storage vessels.

Subpart BB (Benzene Emissions from Benzene Transfer Operations)
Affected sources are all loading racks at which benzene is loaded into tank trucks, railcars, or marine vessels at each benzene production facility and each bulk terminal. Specifically exempted from this regulation are loading racks at which only the following are loaded: benzene-laden waste (covered under Subpart FF of this part), gasoline, crude oil, natural gas liquids, or petroleum distillates. The facility has none of the affected sources.

Subpart FF (Benzene Waste Operations)
Affected sources are benzene-containing waste streams, as identified in EUG 12. Numerous standards apply to tanks, impoundments, and other activities if the total annual benzene (TAB) quantity exceeds 10 megagrams. Test methods and procedures used in calculating the TAB are found in §61.355, paragraphs (a) through (c).

NESHAP, 40 CFR Part 63 [Subparts CC, UUU, ZZZZ, and DDDDD Applicable]

The following paragraphs are general in nature, with some reference to specific facilities. The Specific Conditions contain specific requirements under NESHAP for all Holly affected facilities.

Subpart F (Synthetic Organic Chemical Manufacturing Industry)
The refinery is not a SOCMI facility.

Subpart G (Synthetic Organic Chemical Manufacturing Industry Process Vents, Storage Vessels, Transfer Operations, and Wastewater)
Although the refinery is not a SOCMI facility, the refinery MACT (40 CFR 63 Subpart CC) references provisions of this subpart.

Subpart H (Hazardous Organic NESHAPS {HON} Equipment Leaks)
This MACT contains standards that must be referenced through other MACTs. The refinery is not an affected facility under this subpart.

Subpart R (Gasoline Distribution Facilities {Bulk Gasoline Terminals and Pipeline Breakout Stations})
The refinery is not an affected facility under this subpart, although some provisions of this subpart and of NSPS Subpart XX are invoked by NESHAP MACT Subpart CC.

Subpart Q (Industrial Process Cooling Towers)
The provisions of this subpart apply to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals on or after September 8, 1994, and are either major sources or are integral parts of facilities that are major sources. The refinery ceased the use of chromium-based treatment before this MACT was issued.

Subpart Y (Marine Tank Vessel Tank Loading Operations)
The refinery has no marine vessel loading capability.

<u>Subpart CC</u> (Petroleum Refineries)
Affected facilities include process vents, storage vessels, wastewater streams and treatment, equipment leaks, gasoline loading racks, marine vessel loading systems, and pipeline breakout stations. Of the facilities named in CC, storage tanks, equipment leaks, process vents, wastewater streams and treatment, and a gasoline loading rack are affected facilities at Holly.

Storage tanks
Existing storage tanks with HAP concentrations above $4\%_W$ and which have vapor pressures above 1.5 psia are required to implement controls identical to NSPS Subpart Kb. All tanks in EUGs 18 and 19 are Group 1 Storage Vessels as defined in 63.641 and are to be controlled and monitored per 63.646. Reports and records required for these tanks are found at 63.654. General Provisions for startup/shutdown/malfunction (SSM) plans, as defined at 63.641, are found at 40 CFR 63.6(e)(3). Semi-annual and immediate reporting requirements are listed at 63.10(d)(5). Electronic documentation, including the date of the inspection, any defects noted, and the initials of the inspector, is maintained on-site in the facility's "Refinery Tanks Database."

EUG 20 lists Group 2 Storage Vessels as defined at 63.641. Subparagraph 63.654(i)(1)(iv) requires a determination of Group 2 Tanks. The facility maintains a list of tanks that do not contain any HAPs and are not Group 2 Tanks per 63.640(a)(2).

Process Vents
Any refinery unit process vent with greater than 20 ppmv HAPs and which emits more than 33 kg/day of VOC is subject to control requirements. Subpart CC requires affected vents to be equipped with 98% efficient controls, be vented to a flare, be vented to a combustion unit firebox, or be reduced to 20 ppmv HAP or less. Group 1 Process vents are listed in EUG 14 and Group 2 Process vents are listed in EUG 15. Group 1 Process Vents are vents for which the total organic HAP concentration is greater than or equal to 20 ppmv, and whose total VOC emissions are greater than or equal to 33 kg per day (75 lbs/day). Group 2 Process vents are vents that do not meet the definition of a Group 1 vent. Details of compliance requirements are in the Specific Conditions.

Miscellaneous process vent monitoring provisions are found at §63.644, and test methods and procedures are found at §63.645. The CDU vacuum tower vent is introduced into the flame zone of the CDU H-2 Heater. The LEU T-1 hydrostripper vent is introduced into the flame zone of the LEU H-102 heater. Both vents are exempt from monitoring and performance testing requirements because they are directed into the flame zone of a boiler or process heater.

Equipment Leaks
EUG 8 is a grouping of all the Hazardous Air Pollutant (HAP) fugitive equipment component sources that exist in the refinery. Two compliance options are given at 63.648, consisting of a modified 40 CFR 63, Subpart H method, and a modified 40 CFR 60, Subpart VV method. The Holly Refinery currently chooses to follow the Subpart VV option. The 40 CFR 63 Subpart CC modifications to Subpart VV are primarily in applicability and component exemptions. Applicability is limited to components that contain equal to or more than 5% by weight HAP. Exemptions in addition to Subpart VV include wastewater system drains, storage tank sample valves, and tank mixers. Also, reciprocating pumps in light liquid service and reciprocating

compressors are exempt from 60.482 if recasting the distance pieces or new equipment is required. Subpart VV requires, among other things, leak detection and repair at valves in gas/vapor and light liquid service, and offers three options for such valves. The first is the main standard at 40 CFR 60.482-7, which requires monthly monitoring unless the valve shows no leaks after two successive months after which the valve may be monitored quarterly until it indicates leakage. The second option is given at 60.483-1, in which valves are tested initially, and then annually or as requested by DEQ, and the percentage of leaking valves is not allowed to exceed 2%. The third option is given at 60.483-2, in which good leak performance leads to skip periods of monitoring that leads to annual monitoring so long as leakers remain below 2%. The use of either of the second two options requires prior notification to DEQ. This facility currently follows the base procedures given at 60.482-7, but requests alternative scenario status for the other two options since they represent another form of compliance measurement, and because they require notification to DEQ. Whether these scenarios will be used or not depends on the facility's analysis of the benefits of invoking them. At the present time these options are moot because OAC 252:100-39-15 requires quarterly monitoring of valves. If Section 39-15 is modified in the future to provide reduced monitoring after periods of continuous compliance, the facility will select the compliance option described in §63.648(a)(2).

All Leak Detection and Repair (LDAR) reporting required by 40 CFR 60 Subpart GGG (semi-annual), and 40 CFR 63 Subpart CC (semi-annual) has been consolidated to simplify overlapping requirements. All LDAR reporting is included in the MACT semi-annual report covering all monitoring required from January 1st through June 30th and July 1st through December 31st. Reports are due 60 days after the end of each six month period per 40 CFR 63.654(g).

Gasoline Loading Terminal

Section 63.650 requires compliance with 40 CFR 63 MACT Subpart R for gasoline loading racks with SIC code 2911 and located in a refinery under common control. Note that Subpart R further references standards described in NSPS Subpart XX. EUG 13 is a carbon absorption unit designed and operated to assure compliance with 40 CFR 60.502 (except b, c, and j), with a TOC limit of 10 mg/l, 4 hour average per 63.422(b). Truck certification checks and procedures are done in accordance with 60.502 as modified by 63.422(c). Tests and procedures are done in accordance with 63.425(a)-(c). Truck testing is specified at 63.425(e)-(h). Holly's CEM monitoring is in compliance with 63.427(a) and (b). Reports and records are done in accordance with 63.428(b),(c),(g)(1), and (h)(1)-(3). General Provisions require SSM plans per 40 CFR63.6(e)(3) and SSM semi-annual and immediate reporting is required per 63.10(d)(5)(i)&(ii). Reports are due semi-annually regarding SSM events and within 2 working days for events not complying with the plan. The facility is in compliance based on current records kept on-site.

Wastewater Streams and Treatment

Requirements for the wastewater system are defined at 63.647 as equivalent to the provisions of 40 CFR 61, Subpart FF. Recordkeeping, reporting, and monitoring is also defined at 63.654 to be what is required at 61.356 and 61.357. The facility is in compliance based on compliance with 40 CFR 61, Subpart FF.

Subpart DD (Off-Site Waste and Recovery Operations)
Affected facilities are those that are major under 40 CFR 63.2 and process, recover, or recycle waste that is generated off-site and brought to the facility. The refinery processes no off-site waste. Any recovered material, regardless of processing, is generated on-site.

Subpart UUU (Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units).
This MACT was issued April 11, 2002, and the compliance date for existing units was April 11, 2005. The Platformer (EUG 16) is the only process unit at the facility subject to this MACT. The facility submitted their initial notification of affected source on August 7, 2002. An analysis performed September 25, 2002 through September 28, 2002, during regeneration, demonstrated HCl levels below detectable levels, demonstrating that inorganic HAP emissions are below limitations discussed in 40 CFR 63.1567 and listed at Table 22 of Subpart UUU. Options for compliance with organic HAP limits are discussed in 40 CFR 63.1566. Any performance test must be performed and results submitted no more than 150 days after the compliance date (§63.1671). A performance test was conducted on March 11, 2005. The Notice of Compliance Status Report and the Operation, Maintenance, and Monitoring Plan were submitted on June 16, 2005.

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart previously affected only RICE with a site-rating greater than 500 brake horsepower that are located at a major source of HAP emissions. On January 18, 2008, the EPA published a final rule that promulgates standards for new and reconstructed engines (after June 12, 2006) with a site rating less than or equal to 500 HP located at major sources. The facility has several RICE. Those that have a brake horsepower rating of more than 500 HP are affected units and are listed in EUG 38. However, only two of the engines are subject to the control requirements (EU 256, #3 CT, a 650-hp unit, and EU 257, CT #6, a 615-hp unit, both in circulation pump service). On March 3, 2010, EPA published additional requirements for stationary CI RICE located at area and major sources. On August 20, 2010, EPA published additional requirements for stationary SI RICE located at area and major sources. There are nine engines that are existing CI RICE and are subject to work practice standards. There are five existing SI RICE that are subject to emission limits. There are four emergency SI RICE that are subject to work practice standards. A summary of these proposed requirements for engines located at this facility is shown following.

For each	**You must meet the following requirement, except during periods of startup**	**During periods of startup you must**
1. Emergency CI and black start CI.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]

	necessary.[3]	
6. Emergency SI RICE and black start SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
11. Non-emergency, non-black start 4SRB stationary RICE 100 <HP<500.[1]	Limit concentration of formaldehyde in stationary RICE exhaust to 10.3 ppmvd or less at 15% O_2.	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]

[1]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

[2]Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters at major sources of HAPs. EPA has published various actions regarding implementation of this rule as detailed following:

- September 13, 2004 EPA promulgated standards for major sources
- June 19, 2007 US Court of Appeals for the district of Columbia vacated and remanded the standards
- March 21, 2011 EPA promulgated new standards
- May 18, 2011 EPA published notice of delay of the effective dates until judicial review or EPA reconsideration is completed, whichever is earlier

Section 112(j) of the Clean Air Act addresses situations where EPA has failed to promulgate a standard as required under 112(e) (1) and (3). 112(j) requires case-by-case MACT determination applications to be submitted to the permitting authority within specified time frames. Since 112(j) appears to only address situations where EPA has failed to promulgate standards and not situations in which complete rules are subsequently vacated, confusion existed as to the requirements for these sources. On March 30, 2010, EPA proposed a rule to amend 112(j) to clarify what applies under 112(j). In the proposed rule, EPA clarifies that the intent was that vacated sources should be treated similar to sources where EPA has failed to promulgate a standard. The rule, as proposed, will require case-by-case MACT applications to be submitted to the permitting authority within 90 days after promulgation of these amendments or by the date which the source's permitting authority requests such application. Final action on the amendment is scheduled for the fall of 2011. Compliance with this subpart will be determined based on the requirements of the amended 112(j). This permit may be reopened to address Section 112(j) when necessary. This facility is a major source of HAP.

Subpart GGGGG, Site Remediation. This subpart is applicable to facilities that conduct a site remediation which cleans up a remediation material at a facility that is co-located with one or more other stationary sources that emit HAP and meet the affected source definition. This facility is a major source of HAP and currently conducts site remediation at the facility.

Site remediation at a facility is not subject to this subpart, except for the recordkeeping requirements specified in § 63.7881(c), if the site remediation meets the all of the following conditions:

1. Before beginning the site remediation, you determine that for the remediation material to be excavated, extracted, pumped, or otherwise removed during the site remediation that the total quantity of the HAPs (listed in Table 1 of Subpart GGGGG) is less than 1.10 TPY.
2. The facility prepares and maintains at the facility written documentation to support the determination of the total HAP quantity used to demonstrate compliance with § 63.7881(c)(1). The documentation must include a description of the methodology and data used for determining the total HAPs content of the material.
3. This exemption may be applied to more than one site remediation at the facility provided that the total quantity of the HAPs (listed in Table 1 of Subpart GGGGG) for all of the site remediations exempted under this provision are less than 1.10 TPY.

This facility has documented that all of the site remediations at the facility total less than 1.10 TPY and is only subject to the recordkeeping requirements of this subpart.

Compliance Assurance Monitoring, 40 CFR Part 64 [Not Applicable]
This part applies to any pollutant-specific emission unit at a major source that is required to obtain an operating permit, for any application for an initial operating permit submitted after April 18, 1998, that addresses "large emissions units," or any application that addresses "large emissions units" as a significant modification to an operating permit, or for any application for renewal of an operating permit, if it meets all of the following criteria.

- It is subject to an emission limit or standard for an applicable regulated air pollutant
- It uses a control device to achieve compliance with the applicable emission limit or standard

- It has potential emissions, prior to the control device, of the applicable regulated air pollutant of 100 TPY or 10/25 TPY of a HAP

The initial request for a Part 70 Operating Permit was received on May 19, 1998, so compliance with CAM might be required in this initial permit and was investigated. There are no units with potential emissions at or above the major source thresholds under Part 70, considering control devices. Indeed, many emission units in the refinery have no active control devices. Most of the equipment in the refinery is subject to MACT CC, although MACTs UUU, ZZZZ, and DDDDD may apply to some items within the facility. Each of these MACTs was issued after November 15, 1990, so affected facilities under these MACTs are exempt from CAM, per 64.2(b)(1)(i). CAM for small pollutant-specific emission units will be reviewed when the application for Part 70 Permit renewal is submitted.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Applicable]
Toxic and flammable substances subject to this regulation are present in the facility in quantities greater than the threshold quantities. A Risk Management Plan was submitted to EPA on June 1, 1999, and resubmitted as required by rule.

Stratospheric Ozone Protection, 40 CFR Part 82 [Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).
Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.

This facility does not utilize any Class I & II substances in its manufacturing processes.

SECTION VII. COMPLIANCE

Inspection
Full compliance evaluations (inspections) of the facility are performed regularly. The inspections are complicated, occur in segments, and are performed by various DEQ individuals.

Asbestos Inspection

Rene Koesler, DEQ, ROAT, performed an asbestos inspection at Sun Oil Refinery on March 29, 2004, accompanied by Mr. Mike Matlock and Glen Travis of Sun, and Raul Ibarra of SEC, Inc. (asbestos contractor). Inspection was performed to assess compliance of facility with OAC 252:100-41-16, and EPA NESHAP, Subpart M. No violations were recorded.

Tier Classification and Public Review

This application has been determined to be a **Tier II** based on the request for a PSD construction permit for a major facility. The applicant has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the property. Information on all permit actions is available for review by the public in the Air Quality Section of DEQ Web Page: *http://www.deq.state.ok.us.*

The applicant published the "DEQ Notice of Filing a Tier II Application" and "DEQ Notice of Tier II Draft Permit" in the *Tulsa Daily Commerce & Legal News*, a daily newspaper of general circulation in Tulsa County on January 12, 2012. A copy of the application and draft permit was available at the DEQ Regional Office at Tulsa and the AQD office in Oklahoma City, as well as on the DEQ website. The facility is not located within 50 miles of any other state border. The applicant requested concurrent public and EPA review. No comments were received from the public and the "draft" permit was deemed the "proposed" permit. No comments were received from EPA during their 45-day comment period.

Information on all permit actions is available for review by the public in the Air Quality section of the DEQ Web page: *http://www.deq.state.ok.us/*

Fee Paid

The fee required for construction permit to modify a Part 70 source is $1,500, which has been paid.

SECTION VIII. SUMMARY

This facility was constructed as described in the application. There are no active Air Quality compliance or enforcement issues that would affect the issuance of this permit. Issuance of the construction permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Holly Refining & Marketing – Tulsa LLC **Permit Number 98-014-C (M-19) PSD**
Holly Tulsa Refinery West

The permittee is authorized to construct in conformity with the revised specifications submitted to Air Quality on November 1, 2011 and November 29, 2011. The Evaluation Memorandum dated February 28, 2012, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction or continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein.

1. Points of emissions and emission limits: **[OAC 252:100-8-6(a)]**

FWR (Facility-wide)-1 VISIBLE EMISSIONS AND PARTICULATES
[OAC 252:100-25]

LIMITATIONS

#01 For units that are not subject to NSPS opacity standards or for units subject to the exceptions provided in OAC 252:100-25-3(b)(2) through (4), no discharge of greater than 20% opacity is allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. Opacity standards apply to sources in EUGs 1 through 6, 15 through 17, and 36 through 38, except for those sources subject to the listed exemptions.

MONITORING, RECORDKEEPING, REPORTING

#02 Qualitative opacity assessments, such as Reference Method 22 (RM22) shall be conducted for those processes or operations that are both subject to an opacity standard and are operating. For each emission point, an assessment shall be performed at least once per calendar month except as described below, with at least one week between qualifying readings. A quantitative opacity assessment, such as Reference Method 9 (RM9), shall be performed for each point at which the qualitative assessment indicated visible emissions (VE). If the opacity standard of Subchapter 25 is exceeded, the facility shall investigate the cause of the problem and make repairs as soon as possible, followed by another RM9 test to show that the repairs were successful in eliminating the exceedance. Records of all assessments shall be maintained, including the date, time, and results of the test. Records of all RM9 tests shall also be maintained, including the data sheet showing the various requirements of the method, and the results. Records shall also show any corrective actions taken and the results of all follow-up RM9 testing.

2. Points of emissions and emission limits:

FWR-2 CONTROL OF EMISSIONS OF SULFUR COMPOUNDS [OAC 252:100-31]

LIMITATIONS

#01 OAC 252:100-31-7. Emissions of sulfur compounds from any existing facility shall not result in ambient air concentrations outside the facility property line greater than those specified at 31-7 (a) as to SO_2 and at 31-7(b) as to H_2S.

MONITORING, RECORDKEEPING, REPORTING

#02 Ambient Air Monitoring Plan.

1) Monitor SO_2 ambient air concentrations measured at the east perimeter of the refinery. This will consist of a portable instrument operated for a period of two hours during each day. An average shall be calculated for each hour of measurement. Compliance with the 24-hour concentration limit will be presumed as long as all hourly averages are below the detection limit of 0.4 ppmv SO_2.

2) If either of the two hourly averages calculated pursuant to paragraph 1 is 0.4 ppmv or greater, Holly shall monitor for a second two-hour period on the same calendar day and calculate hourly averages for this second monitoring period. For any calendar day in which three of the four hourly calculated averages exceed 0.4 ppmv, Holly shall review relevant information including, but not necessarily limited to, meteorological data, rail usage, and refinery operations, for the time period during which the measurements were recorded to determine the cause of the measured values. This process is identified as a "root cause analysis."

3) Monitor meteorological data from the Tulsa Office of the National Weather Service.

4) Holly will submit a report that lists all monitoring data, meteorological data, and any calculations performed to the DEQ Regional Office at Tulsa by the 30th day following the end of each two-calendar-month period. Upon completion of one year of such bi-monthly reporting without an exceedance, reporting shall reduce to quarterly, with reports due by the 30th day following each three-calendar-month period. Upon completion of one year of such quarterly reporting without an exceedance, reporting shall reduce to semi-annual, with reports due by the 30th day following each six-calendar-month period.

5) Excess Emissions will be reported pursuant to the requirements of OAC 252:100-9.

3. Points of emissions and emission limits:

FWR-3 PETROLEUM REFINERY PROCESS UNIT TURNAROUND
[OAC 252:100-39-16]

LIMITATIONS

#01 OAC 252:100-39-16(b) For the shutdown, purging and blowdown operation of any petroleum refinery-processing unit the following procedures are required.

1) Recovery of VOCs shall be accomplished during the shutdown or turnaround to a process unit pressure compatible with the flare or vapor system pressure. The unit shall then be purged or flushed to a flare or vapor recovery system using a suitable material such as steam, water or nitrogen. The unit shall not be vented to the atmosphere until pressure is reduced to less than 5 psig through control devices.

2) Except where inconsistent with the "Minimum Federal Safety Standards for the Transportation of Natural and Other Gas by Pipeline," or any State of Oklahoma regulatory agency, no person shall emit VOC gases to the atmosphere from a vapor recovery blowdown system unless these gases are burned by smokeless flares or an equally effective control device as approved by the Division Director.

3) Scheduled refinery unit turnaround may be accomplished without the controls specified in 252:100-39-16(b)(1) and 252:100-39-16(b)(2) during non-oxidant seasons provided the notification to the Division Director as required in 252:100-39-16(b)(3) specifically contains a request for such an exemption. The non-oxidant season is from November 1 through March 31. The facility has been approved to conduct refinery unit turnaround without the controls specified in 252:100-39-16(b)(1) and 252:100-39-16(b)(2) during non-oxidant seasons.

MONITORING, RECORDKEEPING, REPORTING

#02 OAC 252:100-39-16(b)(3). At least fifteen days prior to a scheduled turnaround, a written notification shall be submitted to the Division Director. At a minimum, the notification shall indicate the unit to be shutdown, the date of shutdown, and the approximate quantity of VOCs to be emitted to the atmosphere.

4. Points of emissions and limitations:

FWR-4 CONTROL OF EMISSIONS OF FRIABLE ASBESTOS DURING DEMOLITION AND RENOVATION OPERATIONS [OAC 252:100-40]

MONITORING, RECORDKEEPING, REPORTING

#01 Asbestos OAC:252:100-40-5.

In addition to the requirements set forth for the handling of asbestos found in 40 CFR Part 61 Subpart M, the following provisions shall also apply to owners, operators and other persons.

1) Before being handled, stored or transported in or to the outside air, friable asbestos from demolition/renovation operations shall be:

(A) wetted,

(B) double bagged in six-mil plastic bags, or,

(C) single bagged in one six-mil plastic bag and placed in a disposable drum, or,
(D) contained in any other manner approved in advance, by the Division Director.

2) When demolition/renovation operations must, of necessity take place in the outdoor air, friable asbestos removed in such operations shall be immediately bagged or contained in accordance with paragraph (1) of this Section.

3) Friable asbestos materials used on pipes or other outdoor structures shall not be allowed to weather or deteriorate and become exposed to, or dispersed in the outside air.

4) Friable asbestos materials shall, in addition to other provisions concerning disposal, be disposed of in a facility approved for asbestos by the Oklahoma Department of Environmental Quality, Land Protection Division.

5. Points of emissions and limitations:

EUG 1: EXISTING REFINERY FUEL GAS BURNING EQUIPMENT

Const. Date	EU	Point ID
1948	105A	#1 Boiler
1948	105B	#2 Boiler
1954	106A	#3 Boiler
1957	106B	#4 Boiler
1961	201N	CDU H-1,N,#7
1961	201S	CDU H-1,S,#8
1957	206	Unifiner H-2
1957	207	Unifiner H-3
1957	209	#2 Plat PH-1/2

Const. Date	EU	Point ID
1957	210	#2 Plat PH-3
1957	211	#2 Plat PH-4
1971	214	#2 Plat PH-7
1956	238	PDA B-30
1962	240	PDA B-40
1963	242	LEU H101
1963	244	LEU H-201
1960	246	MEK H-2

(1) Boilers 1 and 2 share the East Stack and Boilers 3 and 4 share the West Stack.
(2) CDU H-1 has two stacks, H-1 North and H-1 South.

LIMITATIONS

#01 OAC 252:100-19-4. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C.

MONITORING, RECORDKEEPING, AND REPORTING

#02 OAC 252:100-8-6(a)(3)(A)(ii). A one time compliance demonstration is listed in Specific Condition #46 for the particulate matter limitation of OAC 252:100-19-4. Compliance with the particulate matter limit can be presumed as long as no changes occur that would increase the particulate emissions. The calculation in Specific Condition #46 shall be maintained in the facility file for 5 years and shall be re-estimated with each permit renewal or with each process change that would increase the particulate potential to emit.

#03 These units are “grandfathered” (constructed prior to any applicable rule). Except for heater PH-4, there are no emission amounts authorized for this EUG under Title V but it is limited to the existing equipment as it is.

#04 EU 211, Platformer heater PH-4, is authorized SO_2 emissions not to exceed 53.4 TPY, rolling 12-month total. Recordkeeping, including fuel use at PH-4 and sulfur content of RFG flowing to PH-4, shall be maintained to support the calculations demonstrating compliance. The maximum firing rate of PH-4 is limited to 29.9 MMBtu/hr on a working day average. PH-4 is limited to a maximum of 10 burners.

[OAC 252:100-8-7.2(b)(2)(A)(iv)]

6. Points of emissions, emission limits, and limitations:

EUG 2: Non-Grandfathered Boilers

CD	EU	Point ID	CO		NOx		PM_{10}		SOx		VOC	
			lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1975	109	#7 boiler, 150MFR	12.6	55.2	30.00	131.4	1.12	4.90	0.10	0.44	0.83	3.62
1976	110	#8 Boiler, 150 MFR	12.6	55.2	30.00	131.4	1.12	4.90	0.10	0.44	0.83	3.62
1976	111	#9 Boiler, 150 MFR	12.6	55.2	30.00	131.4	1.12	4.90	0.10	0.44	0.83	3.62

LIMITATIONS

#01 OAC 252:100-8-6(a)(3)(A)(ii). Boilers shall burn natural gas, including absorber tower offgas, of quality equal to or better than commercial grade.

#02 OAC 252:100-19-4. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C. A one-time compliance demonstration is listed in Specific Condition #46.

#03 OAC 252:100-31-25(a)(1). Sulfur oxide emissions (measured as sulfur dioxide) from any new gas-fired fuel-burning equipment shall not exceed 0.2 lbs/MMBtu-heat input (86 ng/J), three hour average.

#04 OAC 252:100-33-2(a). Nitrogen oxide emissions (measured as nitrogen dioxide) from any new gas-fired fuel-burning equipment shall not exceed 0.20 lbs/MMBtu (86 ng/J) heat input, three-hour average.

MONITORING, RECORDKEEPING, AND REPORTING

#05 When burning inherently low sulfur gas, Holly shall follow the Alternative Monitoring Plan for NSPS Subpart J Refinery Fuel Gas (AMP), approved by EPA.

#06 OAC 252:100-8-6(a)(3)(A)(ii). The boilers are in clean fuel service and compliance with the particulate matter and SO_2 limits are presumed provided that natural gas compliant with #01 is the only fuel used by the boilers.

#07 OAC 252:100-8-6(a)(3)(A)(ii). The facility shall maintain a record demonstrating that natural gas compliant with #01 is the only fuel used in these boilers.

#08 As part of USEPA Consent Decree No. 97CU104H, the valves that may be opened to supply Refinery Fuel Gas after emergency loss of natural gas to the refinery are equipped with car seals and a log is to be maintained and reported after any emergency use. The log shall contain the car seal numbers and date of replacement.

EUG 2a: Boiler Subject to NSPS Subparts Db and Ja

Point ID	NOx		VOC		PM_{10}		CO		SO_2		CO_2e	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
#10 Boiler	5.79	25.4	1.18	5.17	1.63	7.14	18.0	78.96	6.65	10.57	28,031	122,776

LIMITATIONS

#01 The boiler is subject to federal New Source Performance Standards, 40 CFR Part 60, Subpart Db, and shall comply with all applicable requirements, including, but not necessarily limited to those conditions shown following. (NOTE: Permit limitations are more stringent than Db limitations and will result in compliance with Subpart Db.)
[40 CFR 60.40b through 60.49b]

#02 The permittee shall comply with NO_X emission limitations in 40 CFR 60.44b. The boiler shall not discharge into the atmosphere any gases that contain nitrogen oxides (expressed as nitrogen dioxide) in excess of 0.20 lbs/MMBTU.[40 CFR 60.44b(a)(1)(ii)]

#03 Boiler #10 is subject to New Source Performance Standards (NSPS), Subpart Ja and shall comply with all applicable provisions including but not limited to the following.
[40 CFR Part 60, Subpart Ja]

#04 § 60.102a Emission limitations, § 60.102a(g)(1)(ii); The owner or operator shall not burn in any fuel gas combustion device any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

#05 § 60.103a Work practice standards as applicable;

#06 § 60.104a Performance tests as applicable;

#07 Boiler #10 shall only be fired with Subpart Ja compliant refinery fuel gas and/or commercial natural gas. The boiler shall be equipped with a fuel gas meter.
[40 CFR Part 60, Subpart Ja, OAC 252:100-8-6(a)(1)]

#08 OAC 252:100-19-4. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C. A one-time compliance demonstration is listed in Specific Condition #46.

#09 OAC 252:100-31-25(a)(1). Sulfur oxide emissions (measured as sulfur dioxide) from any new gas-fired fuel-burning equipment shall not exceed 0.2 lbs/MMBtu-heat input (86 ng/J), three hour average.

#10 OAC 252:100-33-2(a). Nitrogen oxide emissions (measured as nitrogen dioxide) from any new gas-fired fuel-burning equipment shall not exceed 0.20 lbs/MMBtu (86 ng/J) heat input, three-hour average.

#11 OAC 252:100-8-34(b). CO_2e emissions shall not exceed 206 lb CO_2e / 1000 lb steam produced (30 day rolling average). Steam production shall be determined from a gauge on the outlet of the boiler.

MONITORING, RECORDKEEPING, AND REPORTING

#12 §60.46b Performance test and compliance provisions. An annual performance evaluation of the NO_X CEMS must be conducted in accordance with the Methods specified in 40 CFR Part 60 Appendix B. Exceedances for each 24-hour period shall be reported to Air Quality every calendar quarter.[40 CFR 60.46b(e)(4) & OAC 252:100-2]

#13 The permittee shall comply with the emission monitoring standards of 40 CFR 60.48b.

#14 The permittee shall comply with the reporting and recordkeeping requirements of 40 CFR 60.49b.
#15 § 60.107a Monitoring of operations – (a)(2), (3), and (4); and
#16 § 60.108a Recordkeeping and reporting requirements.
#17 OAC 252:100-8-6(a)(3)(A)(ii). The boiler is required to use gaseous fuel that is compliant with Subpart Ja and compliance with the particulate matter and SO_2 limits are presumed provided that gaseous fuel compliant with #07 is the only fuel used by the boiler.
#18 OAC 252:100-8-6(a)(3)(A)(ii). The facility shall maintain a record demonstrating that gaseous fuel compliant with #07 is the only fuel used in the boiler.
#19 OAC 252:100-8-34(b). The facility shall maintain records of the amount of fuel combusted in the boiler, daily. The facility shall maintain records of the amount of steam produced by the boiler, daily. The facility shall calculate and maintain records of the lb/hr and TPY CO_2e emissions based on metered gas usage and the emission factor from the EPA GHG MRR. The facility shall calculate and maintain records of the lb CO_2e / 1000 lb steam produced (30 day rolling average).
#20 Compliance with the VOC and CO emission limits shall be via initial performance test.

[OAC 252:100-8-6(a)]

7. Points of emissions, emission limits, and limitations:

EUG 3: #2 Plat PH-5 Heater.

In the event of conflict between limits set by permit or by regulation, the more stringent limit shall apply.

#2 PLAT PH-5 HEATER (AUTHORIZED EMISSIONS IN TPY)

CD	**EU**	**Point ID**	**CO**	**NOx**	**PM_{10}**	**SOx**	**VOC**
1990	212	#2 Plat PH-5 65.3 MMBtu/hr	23.55	28.04	2.13	7.23	1.54

LIMITATIONS

#01 OAC 252:100-19-4. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C. A one-time compliance demonstration is listed in Specific Condition #46.
#02 OAC 252:100-31-25(a)(1). Sulfur oxide emissions (measured as sulfur dioxide) from any new gas-fired fuel-burning equipment shall not exceed 0.2 lbs/MMBtu heat input (86 ng/J), three-hour average.
#03 OAC 252:100-33-2(a). Nitrogen oxide emissions (measured as nitrogen dioxide) from any new gas-fired fuel-burning equipment shall not exceed 0.20 lbs/MMBtu (86 ng/J) heat input, three-hour average.
#04 Operator is permitted to burn #2 Plat absorber tower offgas in PH-5, subject to the approved Alternative Monitoring Plan for NSPS Subpart J Refinery Fuel Gas. Fuel gas shall not contain hydrogen sulfide in excess of 230 mg/dscm (0.1 gr/dscf).

MONITORING, RECORDKEEPING, and REPORTING

#05 OAC 252:100-8-6(a)(3)(A)(ii). The heater is in clean fuel service and compliance with the particulate matter and SO_2 limits is presumed provided that natural gas, including low sulfur absorber tower offgas, of quality equal to or better than commercial grade is the only fuel used by the boilers.

#06 Permittee shall comply with SO_X requirements developed in predecessor permits and codified in this permit. Permittee will demonstrate compliance with requirements by meeting the applicable requirements of the AMP mentioned in #04 above.

1) After the first quarter 2005, the operator shall continue to conduct absorber tower offgas monitoring on a semi-annual basis. Monitoring is to occur randomly once every semi-annual period with a minimum of three months between samples.

2) The operator shall follow the Gas Processor Association's Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas using length of Stain Tubes.

3) The operator shall maintain records of the H_2S detector tube monitoring data from the absorber tower feed gas and the absorber tower offgas for five years.

4) The operator shall submit absorber tower monitoring data semi-annually from third quarter 2003 until the end of the first quarter 2005.

5) If the sample detector tube data indicates a potential for the emission limit of 81 ppmv H_2S to be exceeded, the operator shall notify the DEQ of those results before the end of the next business day following the last sample day. "Potential" is defined to be the average result plus three standard deviations. The stream shall be tested daily for a period of two weeks following the notification to DEQ. Sampling shall then continue once per week until the AMP is revised or the facility is allowed to return to the previously existing sampling schedule.

6) Upon DEQ request, the facility shall conduct a test audit for any gas stream with an approved AMP. Such audit shall consist of daily recordings taken over a seven day period.

7) Introduction of a new fuel stream into a fuel gas stream covered by an AMP requires a new application for an AMP.

8) At any time that the absorber tower feed gas H_2S detector tube monitoring records a measurement greater than 81 ppmv, the operator shall replace the absorber tower off-gas to PH-5 Heater with natural gas until the H_2S content returns to 81 ppmv or less.

8. Points of emissions, emission limits, and limitations:

EUG 3A: #2 Plat PH-6 Heater.

In the event of conflict between limits set by permit or by regulation, the more stringent limit shall apply.

#2 PLAT PH-6 HEATER (AUTHORIZED EMISSIONS IN TPY)

CD	EU	Point ID	CO	NOx	PM_{10}	SOx	VOC
1957	213	#2 Plat PH-6 34.8 MMBtu/hr	12.55	14.94	1.14	3.85	0.82

LIMITATIONS

#01 OAC 252:100-19-4. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C. A one-time compliance demonstration is listed in Specific Condition #46.

#02 OAC 252:100-31-25(a)(1). Sulfur oxide emissions (measured as sulfur dioxide) from any new gas-fired fuel-burning equipment shall not exceed 0.2 lbs/MMBtu heat input (86 ng/J), three-hour average.

#03 OAC 252:100-33-2(a). Nitrogen oxide emissions (measured as nitrogen dioxide) from any new gas-fired fuel-burning equipment shall not exceed 0.20 lbs/MMBtu (86 ng/J) heat input, three-hour average.

#04 Operator is permitted to burn #2 Plat absorber tower offgas in PH-6, subject to the approved Alternative Monitoring Plan for NSPS Subpart J Refinery Fuel Gas. Fuel gas shall not contain hydrogen sulfide in excess of 230 mg/dscm (0.1 gr/dscf).

MONITORING, RECORDKEEPING, and REPORTING

#05 OAC 252:100-8-6(a)(3)(A)(ii). The heater is in clean fuel service and compliance with the particulate matter and SO_2 limits is presumed provided that natural gas, including low sulfur absorber tower offgas, of quality equal to or better than commercial grade is the only fuel used by the boilers.

#06 Permittee shall comply with SO_X requirements developed in predecessor permits and codified in this permit. Permittee will demonstrate compliance with requirements by meeting the applicable requirements of the AMP mentioned in #04 above.

1) After the first quarter 2005, the operator shall continue to conduct absorber tower offgas monitoring on a semi-annual basis. Monitoring is to occur randomly once every semi-annual period with a minimum of three months between samples.

2) The operator shall follow the Gas Processor Association’s Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas using length of Stain Tubes.

3) The operator shall maintain records of the H_2S detector tube monitoring data from the absorber tower feed gas and the absorber tower offgas for two years.

4) The operator shall submit absorber tower monitoring data semi-annually from third quarter 2003 until the end of the first quarter 2005.

5) If the sample detector tube data indicates a potential for the emission limit of 81 ppmv H_2S to be exceeded, the operator shall notify the DEQ of those results before the end of the next business day following the last sample day. “Potential” is defined to be the average result plus three standard deviations. The stream shall be tested daily for a period of two weeks following the notification to DEQ. Sampling shall then continue once per week until the AMP is revised or the facility is allowed to return to the previously existing sampling schedule.

6) Upon DEQ request, the facility shall conduct a test audit for any gas stream with an approved AMP. Such audit shall consist of daily recordings taken over a seven day period.

7) Introduction of a new fuel stream into a fuel gas stream covered by an AMP requires a new application for an AMP.

8) At any time that the absorber tower feed gas H_2S detector tube monitoring records a measurement greater than 81 ppmv, the operator shall replace the absorber tower off-gas to PH-6 Heater with natural gas until the H_2S content returns to 81 ppmv or less.

9. Points of emissions, emission limits, and limitations:

EUG 4: Coker H-3 Heater

EU 24	**Pollutant**	**Authorized emissions**	
		Lb/hr	**TPY**
Coker H-3 32.2 MMBtu/hr, constructed 1995	SO_2	2.71	11.8
	NO_X	2.09	9.17
	VOC	0.32	1.41
	CO	1.29	5.64
	PM	0.48	2.12

LIMITATIONS

#01 The heater shall use only commercial pipeline quality natural gas at a maximum rate of 32.2 MMBtu/hr on a working day average.

MONITORING, RECORDKEEPING, and REPORTING

#02 OAC 252:100-8-6(a)(3)(A)(ii). The heater is in clean fuel service provided that pipeline quality natural gas is the only fuel used by the heater. A one-time compliance demonstration is listed in Specific Condition #46. Compliance with the particulate matter and sulfur oxide emission limits are presumed when using pipeline quality natural gas.

#03 OAC 252:100-8-6(a)(3)(A)(ii). The facility shall maintain a record that shows pipeline quality natural gas fuel was used.

10. Point of emissions, emission limits, and limitations:

EUG 5: Coker B-1 Heater, constructed 1992.

LIMITATIONS

#01 The heater shall burn only commercial pipeline quality natural gas, equal or better.

#02 OAC 252:100-19-4. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C.

#03 OAC 252:100-31-25(a)(1). Sulfur oxide emissions (measured as sulfur dioxide) from any new gas-fired fuel-burning equipment shall not exceed 0.2 lbs/MMBtu heat input (86 ng/J) heat input, three hour average, which is compliance while burning permitted natural gas.

#04 OAC 252:100-33-2(a). Nitrogen oxide emissions (measured as nitrogen dioxide) from any new gas-fired fuel-burning equipment shall not exceed 0.20 lbs/MMBtu (86 ng/J) heat input, three-hour average.

MONITORING, RECORDKEEPING, and REPORTING

#05 OAC 252:100-8-6(a)(3)(A)(ii). The heater is in clean fuel service as long as pipeline quality natural gas is the only fuel used by the heater. Compliance with the particulate matter and SO_2 emission limits are presumed. A one-time compliance demonstration is listed in Specific Condition #46.

#06 OAC 252:100-8-6(a)(3)(A)(ii). The facility shall maintain a record demonstrating that pipeline quality natural gas is the only fuel used by the heater.

11. Points of emissions and emission limits:

EUG 6: MEK H-101 Heater, constructed 1977.

Pollutant	Limit (Lbs/MMBtu)
PM_{10}	0.37
SO_2	0.20
NO_X	0.20

LIMITATIONS

#01 The heater shall burn only commercial pipeline quality natural gas, equal or better.

#02 OAC 252:100-19-4. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C.

#03 OAC 252:100-31-25(a)(1). Sulfur oxide emissions (measured as sulfur dioxide) from any new gas-fired fuel-burning equipment shall not exceed 0.20 lbs/MMBtu (86 ng/J), three-hour average.

#04 OAC 252:100-33-2(a). Nitrogen oxide emissions (measured as nitrogen dioxide) from any new gas-fired fuel-burning equipment shall not exceed 0.20 lbs/MMBtu (86 ng/J) heat input, three-hour average.

MONITORING, RECORDKEEPING, and REPORTING

#05 OAC 252:100-8-6(a)(3)(A)(ii). The heater is in clean fuel service provided that pipeline quality natural gas is the only fuel used by the heater. Compliance with the particulate matter and SO_2 emission limits are presumed while in clean fuel service. A one-time compliance demonstration is listed in Specific Condition #46.

#06 OAC 252:100-8-6(a)(3)(A)(ii). The facility shall maintain a record demonstrating that pipeline quality natural gas is used as the fuel.

12. Points of emissions:

EUG 7: REFINERY FUGITIVE EMISSIONS SUBJECT TO 40 CFR 60.590 (Subpart GGG) LEU and Perc Filter.

LIMITS

#01 The facility shall comply with the following applicable requirements of 40 CFR 60 Subpart GGG.

MONITORING

#02 §60.592(a). The operator shall comply with the applicable requirements referenced in Subpart VV at §§60.482-2 to 60.482-10.

#03 §60.592(d). The operator shall comply with the provisions of Subpart VV §60.485, except as provided in §60.593.

RECORDKEEPING

#04 §60.592(e). The operator shall comply with the provisions of Subpart VV §60.486.

REPORTING

#05 §60.592(e). The operator shall comply with the provisions of Subpart VV §60.487. The operator shall submit Semiannual Reports no later than 60 days after January 1st and July 1st of each year.

13. Points of emissions:

EUG 8: REFINERY FUGITIVE EMISSIONS SUBJECT TO 40 CFR 63.640 (Subpart CC) (#2 Platformer, Coker, CDU, MEK Unit, Truck Loading Dock, Tank Farm, Unifiner).

LIMITATIONS

#01 The facility shall comply with the following applicable requirements of 40 CFR 63 Subpart CC.

MONITORING

#02 §63.648 Per paragraph (a), the operator of an existing source subject to the provisions of this subpart shall comply with the applicable provisions of 40 CFR 60 Subpart VV and paragraph (b) of §648 except as provided in subparagraphs (a)(1), (a)(2), and paragraphs (c) through (i) of §648. Subparagraphs (a)(1) and (a)(2) provide that VV applies only to equipment in HAP service and that the calculation method may not be changed except through permit action. Paragraph (c) allows compliance with Subpart H standards in lieu of VV standards under certain circumstances. Paragraphs (d) and (e) define the applicability of Subpart H standards to pumps and valves, paragraph (g) exempts compressors in hydrogen service from the requirements of (a) and (c), and paragraphs (f) and (i) exempt pumps and compressors from certain requirements if replacement of the affected facility or recasting the distance piece is necessary.

RECORDKEEPING

#03 §63.654(d). The operator shall comply with the recordkeeping provisions in paragraph (d)(1) through (d)(6) of §654. The operator shall comply with the provisions of §60.486.

#04 §63.642(e). The owner or operator shall keep copies of all applicable reports and records for at least 5 years. All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours. Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche.

REPORTING

#05 §63.654(d). The operator shall comply with the reporting provisions in paragraph (d)(1) through (d)(6) of §654. The operator shall comply with the provisions of §60.487. The operator shall submit Periodic Reports no later than 60 days after January 1st and July 1st of each year.

14. Points of emissions and limitations

EUG 9: REFINERY FUGITIVE EMISSIONS SUBJECT TO OAC 252:100-39-15

LIMITATIONS

#01 §39-15(b)(2) The operator shall maintain a Leak Detection and Repair Program (LDAR) for all components that have the potential to leak VOCs with a vapor pressure greater than or equal to 0.3 kPa (0.0435 psia) under actual storage conditions.

MONITORING

#02 §39-15(e). Testing and calibration procedures to determine compliance with this section must be consistent with EPA Test Method 21 of 40 CFR Part 60.

#03 §39-15(f).

1) The owner or operator of a petroleum refinery shall conduct a monitoring program consistent with the following provisions. The owner or operator shall:

(A) monitor yearly by the methods referenced in 252:100-39-15(e) all pump seals, pipeline valves in liquid service, and process drains;

(B) monitor quarterly by the methods referenced in 252:100-39-15-(e) all compressor seals, pipeline valves in gas service, and pressure relief valves in gas service;

(C) monitor weekly by visual methods all pump seals;

(D) monitor within 24 hours any pump seal from which VOC liquids are observed dripping;

(E) monitor any relief valve within 24 hours after it has vented to the atmosphere; and,

(F) monitor immediately after repair any component that was found leaking.

2) Pressure relief devices that are connected to an operating flare header, vapor recovery devices, inaccessible valves, storage tank valves, and valves that are not externally regulated are exempt from the monitoring requirements in Condition 3(a); provided, however, such inaccessible valves will be monitored during annual shutdown.

3) The owner or operator of a petroleum refinery, upon the detection of a leaking component that is not repaired on discovery, shall affix a weatherproof and readily visible tag, bearing an identification number and the date the leak is located, to the leaking component. This tag shall remain in place until the leaking component is repaired.

RECORDKEEPING

#04 §39-15(g)

1) The owner or operator of a petroleum refinery shall maintain a leaking components monitoring log which shall contain, at a minimum:

(A) the name of the process unit where the component is located;
(B) the type of component (e.g., valve, seal);
(C) the tag number of the component, if not repaired immediately on discovery;
(D) the date on which a leaking component is discovered;
(E) the date on which a leaking component is repaired;
(F) the date and instrument reading of the recheck procedure after a leaking component is repaired;
(G) the date of the calibration of the monitoring instrument which shall be made available for inspection on request;
(H) those leaks that cannot be repaired until turnaround; and,
(I) the total number of components checked and the total number of components found leaking.

2) The monitoring log shall be retained on-site by the owner or operator for at least two years after the date on which the record was made or the report prepared.
3) The monitoring log shall be made available for inspection at any reasonable time and copies of the log shall be provided to the Division Director, upon written request of the AQD.

REPORTING

#05 §39-15(h). The owner or operator of a petroleum refinery shall:
1) submit a report to the Division Director by the 30th day following the end of each calendar quarter that lists all leaking components that were located during the previous quarter but not repaired within 15 days, all leaking components awaiting unit turnaround, and the total number of components found leaking; and,
2) submit a signed statement with the report attesting to the fact that all monitoring and, with the exception of those leaking components listed in 252:100-39-15(h)(1), all repairs were performed as stipulated in the monitoring program.

15. Point of emissions, and limitations

EUG 11: Lube Extraction Unit (LEU) Flare Subject to 40 CFR 60, Subpart GGG

EU	Point ID	Equipment	Date Installed
269	LEU Flare	John Zink EEF-OS-SA-18 smokeless flare tip	1976

LIMITATIONS

#01 This flare shall comply with the applicable requirements of 40 CFR 60 Subparts GGG and A which includes, but is not limited to, the following Conditions #02 through #08.

#02 §60.18(c)(2). The flare shall be operated with a pilot flame present at all times.

#03 §60.18(c)(1). The flare shall be designed for and operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

#04 §60.18(c)(3)(i)(B)(ii). The flare shall be used only when the net heating value of the gas being combusted is 300 Btu/scf or greater.

#05 §60.18(d). The operator shall ensure that the flare is operated and maintained in conformance with its design.

#06 §60.18(c)(4)(i). Steam-assisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in 40 CFR 60.18(f)(4), less than 60 ft/sec, except as provided below.

1) Steam-assisted flares designed for and operated with an exit velocity, as determined by the methods specified in Paragraph d (see #05 above), equal to or greater than 60 ft/sec but less than 400 ft/sec are allowed if the net heating value of the gas being combusted is greater than 1,000 Btu/scf.

2) Steam-assisted flares designed for and operated with an exit velocity, as determined by the methods specified in 40 CFR 60.18(f)(4), less than the velocity, Vmax, as determined by the method specified in 40 CFR 60.18(f)(5), and less than 400 ft/sec are allowed.

MONITORING, RECORDKEEPING, REPORTING REQUIREMENTS.

#07 §60.486(d). The flare shall comply with the provisions of NSPS General Provisions and in accordance with a DEQ approved alternative test method (ATM), Gary Keele, DEQ attorney, dated 12/20/96. The ATM required Sunoco (Holly) to document calculations based on records under §60.486(d) for:

1) the design specification of the flare to show it will operate smokeless;
2) the calculated maximum exit velocity of the flare based on the design criteria; and
3) the calculated net heating value of the gas relieved to the flare shall be based on the simulated composition of the gas.

The requirements of this ATM were fulfilled on December 1, 1998.

#08 §60.18(f)(2) The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

#09 If the LEU Flare becomes subject to NSPS, Subpart Ja, they shall comply with all applicable provisions of NSPS, Subpart Ja, including but not limited to:

[40 CFR Part 60, Subpart Ja]

i. § 60.102a Emissions limitations;
ii. § 60.103a Work practice standards;
iii. § 60.104a Performance tests;
iv. § 60.107a Monitoring of emissions and operations for process heaters and other fuel gas combustion devices; and
v. § 60.108a Recordkeeping and reporting requirements.

16. Points of emissions and limitations

EUG 12: Wastewater Processing System

EU	Point ID	Equipment	Installed Date
15943	WPU-1	Wastewater Processing Unit and Open Sewers 1. Headworks 2. Storm water Diversion Tank 1039 3. Primary Clarifier 4. North / South DAF 5. Cooling Towers 6. Equalization Basis 7. Aeration Basin 8. North/South Secondary DAF	Various

EU	Point ID	Equipment	Installed Date
		9. Aerobic Digester 10. East/West Firewater Basin 11. Solid Waste Recovery (Centrifuge) 12. Slop Oil Recovery 13. East/West Storm Water Basin	

LIMITATIONS

#01 The facility shall meet the applicable requirements of 40 CFR 63 Subpart CC (Petroleum Refineries) and 40 CFR 61 Subpart FF (Benzene Waste). For facilities with a total annual benzene (TAB) quantity from waste operations falling between 1 and 10 megagrams, compliance with the requirements of FF satisfies the requirements of CC. The Tulsa refinery has a TAB in this range.

MONITORING, RECORDKEEPING, REPORTING REQUIREMENTS

#02 §61.342(a) An owner or operator of a facility at which the total annual benzene quantity from facility waste is less than 10 megagrams per year (Mg/yr) (11 ton/yr) shall be exempt from the requirements of paragraphs (b) and (c) of this section. The total annual benzene quantity from facility waste is the sum of the annual benzene quantity for each waste stream at the facility that has a flow-weighted annual average water content greater than 10 percent or that is mixed with water, or other wastes, at any time and the mixture has an annual average water content greater than 10 percent. The benzene quantity in a waste stream shall be counted only once without multiple counting if other waste streams are mixed with or generated from the original waste stream. Other specific requirements for calculating the total annual benzene waste quantity are as follows.

1) Wastes that are exempted from control under §§61.342(c)(2) and 61.342(c)(3) shall be included in the calculation of the total annual benzene quantity if they have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.

2) The benzene in a material subject to this subpart that is sold shall be included in the calculation of the total annual benzene quantity if the material has an annual average water content greater than 10 percent.

3) Benzene in wastes generated by remediation activities conducted at the facility, such as the excavation of contaminated soil, pumping and treatment of groundwater, and the recover of product from soil or groundwater, shall not be included in the calculation of total annual benzene quantity for that facility.

4) The total annual benzene quantity shall be determined based upon the quantity of benzene in the waste before any waste treatment occurs to remove the benzene except as specified in §61.355(c)(1)(i)(A) through (C).

§61.342(g) Compliance with this subpart shall be determined by review of facility records and results from tests and inspections using methods and procedures specified in § 61.355 of this subpart.

§61.342(h) Permission to use an alternative means of compliance to meet the requirements of §§ 61.342 through 61.352 of this subpart may be granted by the Administrator as provided in § 61.353 of this subpart.

#03 §61.355(a)(4) If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the operator shall:

1) comply with the recordkeeping requirements of §61.356 and reporting requirements of §61.357 of this subpart; and

2) repeat the determination of total annual benzene quantity from facility waste once per year and whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr or more.

#04 §61.356 If the source meets the applicability requirements of 40 CFR 61, Subpart FF, then the permittee shall perform the following.

1) The permittee shall maintain each record in a readily accessible location at the facility site.

2) The permittee shall maintain records that identify each waste stream at the facility pursuant to §61.357(a)(2), and indicate whether or not the waste stream is controlled for benzene emissions in accordance with 40 CFR 61, Subpart FF. In addition, the following records shall be maintained.

A) For each waste stream not controlled for benzene emissions in accordance with 40 CFR 61, Subpart FF, the records shall include all test results, measurements, calculations, and other documentation used to determine the following information for the waste stream: waste stream identification, water content, whether or not the waste stream is a process wastewater stream, annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.

B) For each waste stream exempt from §61.342(c)(1) in accordance with §61.342(c)(3), the records shall include:

(i) All measurements, calculations, and other documentation used to determine that the continuous flow of process wastewater is less than 0.02 liters/minute or the annual waste quantity of process wastewater is less than 10 Mg/yr in accordance with §61.342(c)(3)(i).

(ii) All measurements, calculations, and other documentation used to determine that the sum of the total annual benzene quantity in all exempt waste streams does not exceed 2.0 Mg/yr in accordance with §61.342(c)(3)(ii).

C) Where the process wastewater streams are controlled for benzene emissions in accordance with §61.342(d), the records shall include for each treated process wastewater stream all measurements, calculations, and other documentation used to determine the annual benzene quantity in the process wastewater stream exiting the treatment process.

D) For each facility where waste streams are controlled for benzene emissions in accordance with §61.342(e), the records shall include for each waste stream all measurements, including the locations of the measurements, calculations, and other documentation used to determine that the total benzene quantity does not exceed 6.0 Mg/yr (6.6 ton/yr).

E) Where the annual waste quantity for process unit turnaround waste is determined in accordance with §61.355(b)(5), the records shall include all test results, measurements, calculations, and other documentation used to determine the following information: identification of each process unit at the facility that undergoes turnaround waste, the date of the most recent turnaround for each process unit, identification of each process unit turnaround waste; the annual waste quantity determined in accordance with §61.355(b)(5), the range of benzene concentrations in the waste, the annual average flow-weighted benzene concentration of the waste, and the annual benzene quantity calculated in accordance with §61.355(a)(1)(iii).

F) Where wastewater streams are controlled for benzene emissions in accordance with §61.348(b)(2), the records shall include all measurements, calculations, and other documentation used to determine the annual benzene content of the waste streams and the total annual benzene quantity contained in all waste streams managed or treated in exempt waste management units.

#05 §61.357(c) If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall submit to the DEQ a report that updates the information listed in 1, 2, and 3 following. The report shall be submitted annually and whenever there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more. If the information in the annual report required by 1, 2, and 3 is not changed in the following year, the owner or operator may submit a statement to that effect.

1) Total annual benzene quantity from facility waste determined in accordance with §61.355(a).

2) A table identifying each waste stream and whether or not the waste stream will be controlled for benzene emissions.

3) For each waste stream identified as not being controlled for benzene emissions the following information shall be added to the table.

A) Whether or not the water content of the waste stream is greater than 10 percent;

B) Whether or not the waste stream is a process wastewater stream, product tank draw down, or landfill leachate;

C) Annual waste quantity for the waste stream;

D) Range of benzene concentrations for the waste stream;

E) Annual average flow-weighted benzene concentration for the waste stream; and

F) Annual benzene quantity for the waste stream.

17. Point of emissions, and limitations

EUG 13: Truck Loading Dock Subject to 40 CFR 63, Subpart CC

EU	Point ID	Control Equipment	Date Installed
350	TLD-VRU	Vapor Recovery Unit McGill, Inc. Model MR-1004D	1979

LIMITATIONS

#01 The truck loading dock is subject to 40 CFR 63 Subpart CC (§§63.640 *et seq*) and to OAC 252:100-37-16 and OAC 252:100-39-41. Subpart CC references provisions of MACT R (Gasoline Distribution Facilities) found at 40 CFR 63.420 *et seq* and of NSPS Subpart XX (Bulk Gasoline Terminals) found at 40 CFR 60.500 *et seq*. Conditions #02 through #13 represent the most stringent provisions of each.

#02 §63.422(b) Emissions to the atmosphere from the vapor collection and processing system due to the loading of gasoline cargo tanks shall not exceed 10 milligrams, 4-hour average, of total organic compounds per liter of gasoline loaded.

MONITORING, RECORDKEEPING, REPORTING REQUIREMENTS

#03 §63.650

1) Except as provided in paragraphs b) and c) of §650, each owner or operator of a gasoline loading rack classified under Standard Industrial Classification code 2911 located within a contiguous area and under common control with a petroleum refinery shall comply with Subpart R, §§63.421, 63.422 (a) through (c), 63.425 (a) through (c), 63.425 (e) through (h), 63.427 (a) and (b), and 63.428 (b), (c), (g)(1), and (h)(1) through (h)(3).

2) As used in this section, all terms not defined in §63.641 shall have the meaning given them in Subpart A or in 40 CFR 63, Subpart R. The §63.641 definition of "affected source" applies under this section.

#04 §63.422

1) The permittee shall comply with the requirements in §60.502 except for paragraphs (b), (c), and (j). For purposes of 40 CFR 63, Subpart R, the term "affected facility" used in §60.502 means the loading racks that load gasoline cargo tanks at the bulk gasoline terminals subject to the provisions of 40 CFR 63, Subpart R.

2) The permittee shall comply with §60.502(e) as follows.

A) For the purposes of 40 CFR 63, Subpart R, the term "tank truck" as used in §60.502(e) means "cargo tank."

B) §60.502(e)(5) is changed to read: The permittee shall take steps assuring that the nonvapor-tight gasoline cargo tank will not be reloaded at the facility until vapor tightness documentation for that gasoline cargo tank is obtained which documents that the gasoline cargo tank meets the applicable test requirements in §63.425(e).

#05 §63.425

1) The permittee shall conduct a performance test on the vapor processing system according to the test methods and procedures in §60.503, except a reading of 500 ppmv shall be used to determine the level of leaks to be repaired under §60.503(b).

2) For each performance test conducted under (a) above, the permittee shall determine a monitored operating parameter value for the vapor processing system using the following procedure.

A) During the performance test, continuously record the operating parameter under §63.427(a);

B) Determine an operating parameter value based on the parameter data monitored during the performance test, supplemented by engineering assessments and the manufacturer's recommendations; and

C) Provide for the DEQ's approval the rationale for the selected operating parameter value, and monitoring frequency and averaging time, including data and calculations used to develop the value and a description of why the value, monitoring frequency, and averaging time demonstrate continuous compliance with the emission standard in §63.422(b) or §60.112b(a)(3)(ii).

3) For performance tests performed after the initial test, the permittee shall document the reasons for any change in the operating parameter value since the previous performance test.

#06 §63.427 The permittee shall operate the vapor processing system in a manner not to exceed the operating parameter value for the parameter described in §63.427(a)(1).

#07 §63.428 The permittee shall keep records of the test results for each gasoline cargo tank loading at the facility as follows.

1) Annual certification testing performed under § 63.425(e): and

2) Continuous performance testing performed at any time at that facility under §63.425(f), (g), and (h).

3) The documentation file shall be kept up-to-date for each gasoline cargo tank loading at the facility. The documentation for each test shall include, as a minimum, the following information.

A) Name of test.

(i) Annual Certification Test -- Method 27 (§ 63.425(e)(1)),

(ii) Annual Certification Test -- Internal Vapor Valve (§ 63.425(e)(2)),

(iii) Leak Detection Test (§63.425(f)), Nitrogen Pressure Decay Field Test (§63.425(g)), or

(iv) Continuous Performance Pressure Decay Test (§ 63.425(h)).

B) Cargo tank owner's name and address.

C) Cargo tank identification number.

D) Test location and date.

E) Tester name and signature.

F) Witnessing inspector, if any: Name, signature, and affiliation.

G) Vapor tightness repair: Nature of repair work and when performed in relation to vapor tightness testing.

H) Test results:

(i) Test pressure

(ii) Pressure or vacuum change, mm of water;

(iii) Time period of test;

(iv) Number of leaks found with instrument; and

(v) leak definition.

#08 §63.427(a) The permittee shall keep an up-to-date, readily accessible record of the continuous monitoring data required under §63.427(a). This record shall indicate the time intervals during which loadings of gasoline cargo tanks have occurred or, alternatively, shall record the operating parameter data only during such loadings. The date and time of day shall also be indicated at reasonable intervals on this record.

Per §63.428(c)(3), if the permittee requests approval to use a vapor processing system or monitor an operating parameter other than those specified in §63.427(a), the permittee shall submit a description of planned reporting and recordkeeping procedures and the administrator will specify appropriate reporting and recordkeeping requirements as part of the review of the permit application.

#09 §63.10(e)(3) The permittee shall submit an excess emissions report to the DEQ in accordance with § 63.10(e)(3), whether or not a CMS is installed at the facility. The following occurrences are excess emissions events under this subpart, and the following information shall be included in the excess emissions report, as applicable:

1) Each exceedance or failure to maintain, as appropriate, the monitored operating parameter value determined under §63.425(b). The report shall include the monitoring data for the days on which exceedances or failures to maintain have occurred, and a description and timing of the steps taken to repair or perform maintenance on the vapor collection and processing systems or the CMS.

2) Each instance of a nonvapor-tight gasoline cargo tank loading at the facility in which the permittee failed to take steps to assure that such cargo tank would not be reloaded at the facility before vapor tightness documentation for that cargo tank was obtained.

3) Each reloading of a nonvapor-tight gasoline cargo tank at the facility before vapor tightness documentation for that cargo tank is obtained by the facility in accordance with §63.422(c)(2).

#10 §63.10(b) and 63.422(c)(2) The permittee shall include in a semi-annual report to the DEQ the loading of each gasoline cargo tank for which vapor tightness documentation had not been previously obtained by the facility.

#11 OAC 252:100-39-41(e)(3) The facility shall monitor the loading facility annually in accordance with EPA Method 21 Leak Test. Leaks greater than 5,000 ppmv shall be repaired within 15 days. Facilities shall retain inspection and repair records for at least two years.

#12 OAC 252:100-39-41(e)(4) The facility shall not fill vessels that do not display a current tag meeting the requirements of 100-39-41(e)(4)(A)(iv).

#13 §63.642(e) The owner or operator shall keep copies of all applicable reports and records for at least 5 years. All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours. Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche.

18. Points of emissions and limitations

EUG 14: Group 1 Process Vents Subject to 40 CFR 63, Subpart CC

EU	Equipment Point ID	Control Device
N/A	CDU Vacuum Tower Vent	CDU H-2 Heater
N/A	LEU T-201 Hydrostripper Tower Vent	LEU H-102 Heater
N/A	Coker Enclosed Blowdown Vent	Platformer Flare, WPU Flare, Coker Flare

LIMITATIONS

#01 The operator shall comply with the applicable requirements of 40 CFR 63 Subparts CC and A. As noted in previous instances, CC requirements reference other standards.

#02 §63.643(a) The operator shall either (1) reduce the emissions of organic HAPs using a flare that meets the requirements of 63.11(b), or (2) reduce the emissions of organic HAPs, using a control device, by 98% weight-percent or to a concentration of 20 parts per million by volume, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent.

#03 §63.643(b) For the heaters used to comply with the percentage of reduction requirement or concentration limit, the vent stream shall be introduced into the flame zone of such heater, or in a location such that the required percent reduction of concentration is achieved.

MONITORING, RECORDKEEPING, AND REPORTING

#04 §63.11 The permittee shall use DEQ-approved testing methods to demonstrate compliance with the standards for flares. Because DEQ has determined that flares EU 266 and EU 268 cannot practically be tested under normal operating conditions, testing is required only at EU 267 (Plat Flare). DEQ has further determined that performance tests for EU 267 are representative of the compliance status for all three flares, as EU 266 and 268 have design characteristics very similar to those of EU 267. The test methods include, but are not limited to, the following.

1) EPA Test Method 22 in Appendix A of 40 CFR Part 60 shall be used to determine the compliance of this flare with the visible emission provisions of 40 CFR 63.11. The observation period is 2 hours and shall be used according to EPA Method 22.

2) EPA Method 2, 2A, 2C, or 2D for determination of flare velocity. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

3) EPA Method 3A for determining flue gas composition and molecular weight.

4) EPA Method 18 for determination of hydrocarbon constituents.

5) The net heating value of the gas being combusted in the flare shall be computed as stated in 40 CFR 63.11(b)(6).

6) EPA Method 18 and ASTM D 2504-67 shall be used to determine the concentration of sample component “i” in the equation stated in 40 CFR 63.11(b)(6)(ii).

7) ASTM D 2382-76 shall be used to determine the net heat of combustion of component “i” referenced in 40 CFR 63.11(b)(6)(ii), if published values are not available or cannot be calculated.

#05 §63.116(b) The operator is not required to conduct a performance test when the control device used is any boiler or process heater with a design heat input capacity of 44 megawatts (150 MMBtu/hr) or greater or is any boiler or process heater in which all vent streams are introduced into the flame zone.

#06 §63.644(a) Monitoring requirements.

1) Where a flare is used, a device (including but not limited to a thermocouple, or an ultraviolet beam sensor, or infrared sensor) capable of continuously detecting the presence of a pilot flame shall be required.

2) Any boiler or process heater with a design heat input capacity greater than or equal to 44 megawatt or any boiler or process heater in which all vent streams are introduced into the flame zone is exempt from monitoring.

#07 §63.644(c). An operator using a vent system that contains bypass lines that could divert a vent stream away from the control device shall comply with (1) or (2). Equipment such as low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, pressure relief valves needed for safety reasons, and equipment subject to §63.648 are not subject to this paragraph.

1) Install, calibrate, maintain, and operate a flow indicator that determines whether a vent stream flow is present at least once every hour. The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere; or

2) Secure the bypass line valve in the closed position with a car-seal or a lock-and-key type configuration. A visual inspection of the seal or closure mechanism shall be performed at least once every month to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

#08 §63.654(i)(3)(i). The flare monitoring systems shall measure and record data values at least once every hour.

#09 §63.654(g). The operator shall submit Periodic Reports no later than 60 days after the end of each 6-month period when any compliance exception occurs. A Periodic Report is not required if compliance exceptions do not occur during the 6-month period.

#10 §63.654(g)(6). For miscellaneous process vents for which continuous parameter monitors are required, periods of excess emissions shall be identified in the Periodic Reports and shall be used to determine compliance with the emission standards. Periods of excess emissions mean any of the following conditions.

1) An operating day when all pilot flames of a flare are absent.

2) An operating day when monitoring data required to be recorded are available for less than 75 percent of the operating hours.

#11 §63.654(g)(6)(iii). Periods of start-up, shutdown, and malfunction and periods of performance testing and monitoring system calibration shall not be considered periods of excess emissions. Malfunctions may include process unit, control device, or monitoring system malfunctions.

#12 §63.642(e) The owner or operator shall keep copies of all applicable reports and records for at least 5 years. All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours. Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche.

19. Points of emissions:

EUG 15: Group 2 Process Vents Subject to 40 CFR 63, Subpart CC

EU	**Equipment Point ID**	**Control Device**
N/A	MEK T-7 Vent	NA
N/A	LEU-T101 Vent	NA
N/A	LEU D-101 Vent	NA
N/A	MEK Flue Gas Oxygen Vent	NA
N/A	MEK Knockout Drum O-52	LEU Flare

LIMITATIONS

None; controls are not required.

MONITORING, RECORDKEEPING. REPORTING

#01 §63.640(l)(2)(ii). If a deliberate operational process change to an existing petroleum refining process unit causes a Group 2 emission point in EUG 15 to become a Group 1 emission point, the owner or operator shall be in compliance upon initial start-up unless the owner or operator demonstrates to the DEQ that achieving compliance will take longer than making the change. If this demonstration is made to the DEQ's satisfaction, the owner or operator shall follow the procedures in paragraphs (m)(1) through (m)(3) of this section (Conditions #02(1) through (3) below) to establish a compliance date.

#02 §63.640(m). If a change is made to a petroleum refining process unit subject to this subpart, and the change causes a Group 2 emission point in EUG 15 to become a Group 1 emission point, and the owner cannot achieve compliance immediately, then the owner or operator shall comply with the requirements of this subpart for existing sources for the Group 1 emission point as expeditiously as practicable, but in no event later than 3 years after the emission point becomes Group 1.

1) The owner or operator shall submit to the DEQ for approval a compliance schedule, along with the justification for the schedule.

2) The compliance schedule shall be submitted within 180 days after the change is made, unless the compliance schedule has been previously submitted to the permitting authority. If it is not possible to determine until after the change is implemented whether the emission point has become Group 1, the compliance schedule shall be submitted within 180 days of the date when the effect of the change is known to the source. The compliance schedule may be submitted in the next Periodic Report if the change is made after the date the Notification of Compliance Status report is due.

3) The DEQ shall approve or deny the compliance schedule or request changes within 120 calendar days of receipt of the compliance schedule and justification. Approval is automatic if not received from the DEQ within 120 days of receipt.

#03 §63.642(e) The owner or operator shall keep copies of all applicable reports and records for at least 5 years. All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours. Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche.

20. Point of emissions and limitations

EUG 16: Process Vent Subject to 40 CFR 63, Subpart UUU

EU	Equipment	Control Device
N/A	#2 Platformer Catalytic Reforming Vent	NA

LIMITATIONS

#01 §63.1567(a)(1) The operator shall not exceed the emissions of hydrogen chloride listed in Table 22 of NESHAP, Subpart UUU.

#02 §63.1567(a)(2) The operator shall meet the site specific operating limits in Table 23 of NESHAP, Subpart UUU.

#03 §63.1567(a)(3) The unit shall be operated at all times in accordance with the procedures in the operation, maintenance, and monitoring (OMM) plan submitted pursuant to the requirements of §63.1574(f).

MONITORING, RECORDKEEPING, REPORTING

#04 The OMM plan shall contain all appropriate monitoring requirements.

#05 Recordkeeping and reporting requirements are described in §63.1575.

21. Point of emissions, and limitations [OAC 252:100-8-6(a)]

EUG 17: Coker Enclosed Blowdown

LIMITATIONS

#01 All non-condensable vapors from the Enclosed Coker Blowdown system shall be ducted to a flare. The Coker Enclosed Blowdown Vent is regulated under EUG 14.

22. Points of emissions and limitations

EUG 18: 40 CFR 63.640 (Subpart CC), Existing Group 1 Internal Floating Roof Storage Vessels. IFR Tanks emptied and degassed since 8/18/98, 63.640(h)(4).

Tank #	EU	Point ID
13	6333	Tk13
21	6336	Tk21
22	6337	Tk22
31	6340	Tk31
153	6346	Tk153
186	6348	Tk186
187	6349	Tk187
188	13592	Tk188
242	6359	Tk242
244	6360	Tk244
473	6387	Tk473
474	6388	Tk474
411	13579	Tk411
413	6341	Tk413
502	1359	Tk502
742	6392	Tk742

LIMITATIONS

#01 The tanks are subject to 40 CFR 63 Subpart CC (§63.640 *et seq*), to OAC 252:100-37-15(a) and (b) and to OAC 252:100-39-41(a), (b), and (e)(1). Subpart CC references provisions of MACT G (SOCMI) found at 40 CFR 63.110 *et seq*. Conditions #02 through #09 represent the most stringent provisions of each.

#02 §63.119(a)(1). The tank may not store VOCs that have a maximum true vapor pressure that exceeds 11.1 psia.

#03 §63.646 The operator of a Group 1 storage vessel subject to 40 CFR 63, Subpart CC shall comply with the applicable requirements of §§63.119 through 63.121 except as provided in paragraphs (b) through (l) of 40 CFR 63.646.

MONITORING, RECORDKEEPING, REPORTING REQUIREMENTS:

#04 §63.646(b)(2) When the operator and the DEQ do not agree on whether the annual average weight percent organic HAP in the stored liquid is above or below four (4) percent for a storage vessel, EPA Method 18 of 40 CFR 60, Appendix A, shall be used.

#05 The operator shall visually inspect the internal floating roof and the seal according to the following schedule.

1) §63.120(a)(2) For vessels equipped with a single-seal system:

A) §63.120(a)(2)(i) Visually inspect the internal floating roof and the seal through manholes and roof hatches on the fixed roof at least once every twelve (12) months after initial fill, or at least once every 12 months after the compliance date;

B) 63.120(a)(2)(ii) Visually inspect the internal floating roof and the seal each time the storage vessel is emptied and degassed, and at least once every ten (10) years.

2) §63.120(a)(3) For vessels equipped with a double-seal system, the owner or operator shall complete the inspections listed under (i) below, or the inspections listed under both (ii) and (iii) below.

A) §63.120(a)(3)(i) The owner or operator shall visually inspect the internal floating roof, the primary seal, and the secondary seal each time the storage vessel is emptied and degassed and at least once every 5 years after the compliance date; or

B) §63.120(a)(3)(ii) The owner or operator shall visually inspect the internal floating roof and the secondary seal through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill, or at least once every 12 months after the compliance date, and

C) §63.120(a)(3)(iii) Visually inspect the internal floating roof, the primary seal, the secondary seal, gaskets, slotted membranes, and sleeve seals (if any) each time the vessel is emptied and degassed and at least once every 10 years after the compliance date.

#06 §63.646(b)(1) The operator may use good engineering judgment or test results to determine the stored liquid weight percent total organic HAP for purposes of group determination. Data, assumptions, and procedures used in the determination shall be documented.

#07 1) §63.120(a)(5) Except as provided in subcondition (2) (§63.120(a)(6)) of this condition, for all inspections required by Condition #05(2) (§63.120(a)(3)) for this source, the operator shall notify the DEQ in writing at least thirty (30) calendar days prior to the refilling of each storage vessel to afford the DEQ the opportunity to have an observer present.

2) §63.120(a)(6) If the inspection of this source required by Condition #05(§63.120(a)(3)) is not planned and the operator could not have known about the inspection thirty (30) calendar days in advance of refilling the vessel, the operator shall notify the DEQ at least seven (7) calendar days prior to the refilling of the storage vessel. Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. Alternately, the notification including the written documentation may be made in writing and sent so that it is received by the DEQ at least seven (7) calendar days prior to refilling.

3) §63.646(l) The Department may waive the notification requirements of §63.646 for all or some storage vessels subject to these requirements. The Department may also grant permission to refill storage vessels sooner than thirty (30) days after submitting the notifications specified in subcondition (2) (§63.120(a)(6)), above, for all storage vessels or for individual storage vessels on a case-by-case basis.

4) §63.122(d) If a failure is detected during the annual monitoring inspections of Condition #05(1)(A) or (2)(B) (§§63.120(a)(2)(i) and 63.120(a)(3)(ii)), the operator shall report the following information in the Periodic Report. For this subcondition, a failure is defined as anytime in which the internal floating roof is not resting on the surface of the liquid inside the storage vessel and is not resting on the leg supports; or there is liquid on the floating roof; or the seal is detached from the internal floating roof; or there are holes, tears, or other openings in the seal or seal fabric; or there are visible gaps between the seal and the wall of the storage vessel.

A) Date of the inspection.
B) Identification of each storage vessel in which a failure was detected.
C) Description of the failure.
D) Describe the nature of and date the repair was made or the date the storage vessel was emptied.

5) §63.122(e) If a failure is detected during the monitoring inspection of Condition #05(2) (§63.120(a)(3)), the operator shall report the following information in the Periodic Report. For this subcondition, a failure is defined as any time in which the internal floating roof has defects; or the primary seal has holes, tears or other openings in the seal or the seal fabric.

A) Date of the inspection.
B) Identification of each storage vessel in which a failure was detected.
C) Description of the failure.
D) Describe the nature of and date the repair was made.

6) §63.122 If an extension is utilized per Condition #08(7) (§63.120(a)(4)) for repairs discovered during inspections required in Condition #05(1)(A) and (2)(B) (§§63.120(a)(2)(i) and 63.120(a)(3)(ii)), the operator shall, in the next Periodic Report, include the following:

A) Identify the storage tank.
B) Description of the failure.
C) Document that alternate storage capacity was not available.
D) A schedule of actions that will ensure that the control equipment will be repaired or that the vessel will be emptied as soon as practical, and/or a description of the nature of and date the repair was made.

#08 1) §63.119(b)(1) The internal floating roof shall be floating on the liquid surface at all times except when the floating roof must be supported by the leg supports during the following periods.

A) During the initial fill.
B) After the vessel has been completely emptied and degassed.
C) When the vessel is completely emptied before being subsequently refilled.

2) §63.119(b)(2) When the floating roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as soon as practical.

Note: The intent of (1) and (2) above is to avoid having a vapor space between the floating roof and the stored liquid for extended periods. Storage vessels may be emptied for purposes such as routine storage vessel maintenance, inspections, petroleum liquid deliveries, or transfer operations. Storage vessels where liquid is left on walls, as bottom clingage, or in pools due to floor irregularity are considered completely empty.

3) §63.119(b)(3) Each internal floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device shall consist of one of the following devices:

A) A liquid mounted seal.

B) A metallic shoe seal.

C) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous seals.

4) §63.119(b)(4) Automatic bleeder vents are to be closed at all times when the roof is floating, except when the roof is being floated off or is being landed on the roof leg supports.

5) §63.119(b)(6) If a cover or lid is installed on an opening on a floating roof, the cover or lid shall remain closed except when the cover or lid must be open for access.

6) §63.119(b)6) Rim space vents are to be set to open only when the floating roof is not floating or when the pressure beneath the rim seal exceeds the manufacturer's recommended setting.

7) §63.120(a)4) If during the inspections required by Condition #05(1)(B) or (2)(B), above, the internal floating roof is not resting on the surface of the liquid inside the storage vessel and is not resting on the leg supports; or there is liquid on the floating roof; or the seal is detached; or there are holes or tears in the seal fabric; or there are visible gaps between the seal and the wall of the storage vessel, the operator shall repair the items or empty and remove the storage vessel from service within forty-five (45) calendar days. If a failure that is detected during such inspections cannot be repaired within forty-five (45) calendar days and if the vessel cannot be emptied within forty-five (45) calendar days, the operator may utilize up to 2 extensions of up to thirty (30) additional calendar days each. Documentation of a decision to utilize an extension shall include a description of the failure, shall document that alternate storage capacity is unavailable, and shall specify a schedule of actions that will ensure that the control equipment will be repaired or the vessel will be emptied as soon as practical.

8) §63.120(a)(7) If during the inspections required by the monitoring inspections of Condition #05(2), above, the internal floating roof has defects or the primary seal has holes, tears, or other openings in the seal or the seal fabric, the operator shall repair the items as necessary so that none of the conditions specified in this subcondition exist before refilling the storage vessel with organic HAP.

#09 §63.642(e) The owner or operator shall keep copies of all applicable reports and records for at least 5 years. All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours. Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche.

23. Points of emissions and limitations

EUG 19: 63.640 (Subpart CC) Existing Group 1 External Floating Roof Storage Vessels. External Floating Roof Tanks emptied and degassed since 8/18/98, 63.640(h)(4).

Tank #	EU	Point ID
199	6353	Tk199
307	6367	Tk307
750	6396	Tk750
752	6398	Tk752
755	6399	Tk755
779	6401	Tk779
874	6405	Tk874

LIMITATIONS

#01 The tanks are subject to 40 CFR 63 Subpart CC (§63.640 *et seq*), to OAC 252:100-37-15(a) and (b) and to OAC 252:100-39-41(a), (b), and (e)(1). Subpart CC references provisions of MACT G (SOCMI) found at 40 CFR 63.110 *et seq*. Many of the requirements overlap, so conditions #02 through #09 represent the most stringent version of each.

#02 1) §63.119(a)(1) The tanks may not store VOCs that have a true vapor pressure that exceeds 11.1 psia.

2) §63.120(b)(3) The accumulated areas of gaps between the vessel wall and the primary seal, as calculated according to subcondition #05(3), shall not exceed 10 square inches per foot of vessel diameter, and the width of any portion of any gap shall not exceed 1.5 inches.

(3) §63.120(b)(4) The accumulated area of gaps between the vessel wall and the secondary seal, as determined by subcondition #05(4), below, shall not exceed 1.0 square inch per foot of vessel diameter and the width of any portion of any gap shall not exceed 0.5 inches. These seal gap requirements may be exceeded during the measurement of primary seal gaps as required by § 63.646 per 63.119(c(1)(iii).

MONITORING, RECORDKEEPING, REPORTING

#03 §63.646 The operator of a Group 1 storage vessel subject to this 40 CFR 63, Subpart CC shall comply with the applicable requirements of §§63.119 through 63.121 except as provided in paragraphs (b) through (l) of §646.

#04 §63.646(b)(2) When the operator and the DEQ do not agree on whether the annual weight percent organic HAP in the stored liquid is above or below four (4) percent for a storage vessel, EPA Method 18, of 40 CFR 60, Appendix A shall be used.

#05 1) §63.120(b)(1) Except as provided in subcondition (5), below, the operator shall determine the gap areas and maximum gap widths between the primary seal and the wall of the storage vessel, and the secondary seal and the wall of the storage vessel according to the following frequency.

A) §63.120(b)(1)(i) Measurements of gaps between the vessel wall and the primary seal shall be performed at lest once every five (5) years.

B) §63.120(b)(1)(iii) Measurements of gaps between the vessel wall and the secondary seal shall be performed at least once per year.

C) §63.120(b)(1)(iv) If any storage vessel ceases to store organic HAP for a period of one (1) year or more, or if the maximum true vapor pressure of the total organic HAPs in the stored liquid falls below the value defining Group 1 storage vessels for a period of one (1) year or more, measurements of gaps between the vessel wall and the primary seal, and the gaps between the vessel wall and the secondary seal shall be performed within ninety (90) calendar days of the vessel being refilled with organic HAP.

2) §63.120(b)(2) Except as provided in subcondition (5), below, the operator shall determine gap widths and gap areas in the primary and secondary seals (seal gaps) individually by the procedures described in subconditions (A), (B), and (C), following.

A) §63.120(b)(2)(i) Seal gaps, if any, shall be measured at one or more floating roof levels when the roof is not resting on the roof leg supports.

B) §63.120(b)(2)(ii) Seal gaps, if any, shall be measured around the entire circumference of the vessel in each place where a one-eighth (1/8) inch diameter uniform probe passes freely (without forcing or binding against the seal) between the seal and the wall of the storage vessel. The circumferential distance of each such location shall also be measured.

C) §63.120(b)(2)(iii) The total surface area of each gap described in subcondition (b)(2) above shall be determined by using probes of various widths to measure accurately the actual distance from the vessel wall to the seal and multiplying each such width by its respective circumferential distance.

3) §63.120(b)(3) The operator shall add the gap surface area of each gap location for the primary seal and divide the sum by the nominal diameter of the vessel.

4) §63.120(b)(4) The operator shall add the gap surface area of each gap location for the secondary seal and divide the sum by the nominal diameter of the vessel.

5) §63.120(b)(7) If the operator determines that it is unsafe to perform the seal gap measurements required in subconditions (1) and (2), above, or to inspect the vessel to determine compliance with subconditions #08(8) and (9) because the floating roof appears to be structurally unsound and poses an imminent or potential danger to inspecting personnel, the operator shall comply with the requirements of either (A) or (B), following.

A) The operator shall measure the seal gaps or inspect the storage vessel no later than thirty (30) calendar days after the determination that the roof is unsafe, or

B) The operator shall empty and remove the storage vessel from service no later than forty-five (45) calendar days after determining that the roof is unsafe. If the vessel cannot be emptied within forty-five (45) calendar days, the operator may utilize up to 2 extensions of up to thirty (30) additional calendar days each. The decision to utilize an extension must be documented per Condition #06(b).

6) §63.120(b)(10) The operator shall visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

#06 1) §63.646(b)(1) The operator may use good engineering judgment or test results to determine the stored liquid weight percent total organic HAP for purposes of group determination. Data, assumptions, and procedures used in the determination shall be documented.

2) §63.120(b)(8) If the operator utilizes the extension specified in Condition #05(5)(B), or Condition #08(11), for this source, the operator shall document the decision. Documentation of a decision to utilize the extension shall include: a description of the failure, document that alternate storage capacity is unavailable, and specify a schedule of actions that will ensure that the control equipment will be repaired or the vessel will be emptied, as soon as practical.

#07 1) §63.120(b)(9) Except as provided in subcondition (2), below, for all the inspections required by Condition #05(6), the operator shall notify the DEQ in writing at least thirty (30) calendar days prior to the refilling of each storage vessel with organic HAP to afford the DEQ the opportunity to inspect the storage vessel prior to refilling.

2) §63.120(b)(10)(iii) If the inspection required by Condition #05(6), above, is not planned and the operator could not have known about the inspection thirty (30) calendar days in advance of refilling the vessel with organic HAP, the operator shall notify the DEQ at least seven (7) calendar days prior to refilling of a storage vessel. Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. Alternately, the notification including the written documentation may be made in writing and sent so that it is received by the DEQ at least seven (7) calendar days prior to refilling.

3) §63.646(l) The DEQ can waive the notification requirements specified in Conditions #07(1) and (2) for all or some storage vessels subject to these requirements. The Department may also grant permission to refill storage vessels sooner than thirty (30) days after submitting the notifications specified in Condition #07(1) or sooner than 7 days after submitting the notification required by Condition #07(2) for all storage vessels at a refinery or for individual storage vessels on a case-by case basis.

4) §63.120(b)(9) The operator shall notify the DEQ in writing thirty (30) calendar days in advance of any gap measurements required by Condition #05(1) or (2), above, to afford the DEQ the opportunity to have an observer present.

5) §63.122(e)(1) If seal gaps in exceedance of Condition #02(1) and (2), above, are found during the inspections required by Condition #05(1) or if the specification in Conditions #07(8) and (9) are not met, the operator shall report the following information in the Periodic Report:

A) Date of the seal gap measurement.

B) The raw data obtained in the seal gap measurement and the calculations described in Conditions #04(3) and (4).

C) Description of any seal condition specified in Conditions #08(8) and (9) that is not met.

D) Description of the nature of and date the repair was made, or the date the storage vessel was emptied.

6) §63.122(e)(3)(ii) If a failure is detected during the inspection required by Condition #05(6) (i.e., internal inspection), the operator shall report the following information in the Periodic Report. A failure is defined as any time in which the external floating roof has defects; or the primary seal has holes, tears, or other openings in the seal or the seal fabric; or the secondary seal has holes, tears, or other openings in the seal or the seal fabric.

A) Date of the inspection.

B) Identification of each storage vessel in which a failure was detected.
C) Description of the failure.
D) Describe the nature of and date the repair was made.

7) §63.120(b)(8) If an extension is utilized in accordance with Condition #08(11), below, the operator shall, in the next Periodic Report include the following.
A) Identify the storage vessel.
B) Description of the failure.
C) Document that alternate storage capacity was not available.
D) Describe the nature of and date the repair was made.

#08 1) §63.119(c)(3) The external floating roof shall be floating on the liquid surface at all times except when the floating roof must be supported by the leg supports during the following periods.
A) During the initial fill.
B) After the vessel has been completely emptied and degassed.
C) When the vessel is completely emptied before being subsequently refilled.

2) §63.119(c)(4) When the floating roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as soon as practical.

Note: The intent of subconditions (1) and (2), above, is to avoid having a vapor space between the floating roof and the stored liquid for extended periods. Storage vessels may be emptied for purposes such as routine storage vessel maintenance, inspections, petroleum liquid deliveries, or transfer operations. Storage vessels where liquid is left on walls, as bottom clingage, or in pools due to floor irregularity are considered completely empty.

3) §63.119(c)(1) Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device meets the following criteria.
A) §63.119(c)(1)(i) Consist of two seals, one above the other.
B) §63.119(c)(1)(ii) The primary seal shall be either a metallic shoe seal or a liquid-mounted seal.

4) §63.119(c)(1)(iii) Except during inspections required by Condition #05, both the primary and secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion.

5) §63.119(c)(2)(iii) Automatic bleeder vents are to be closed at all times when the roof is floating, except when the roof is being floated off or is being landed on the roof leg supports.

6) §63.119(c)(2)(ii) If a cover or lid is installed on an opening on a floating roof, the cover or lid shall remain closed except when the cover or lid must be open for access.

7) §63.119(c)(2)(iv) Rim space vents are to be set to open only when the floating roof is not floating or when the pressure beneath the rim seal exceeds the manufacturer's recommended setting.

8) §63.120(b)(3) The primary seal shall also meet the following requirements:
A) Where a metallic shoe seal is in use, one end of the metallic shoe shall extend into the stored liquid and the other end shall extend a minimum vertical distance of 24 inches above the stored liquid surface.

B) There shall be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

9) §63.120(b)(6) The secondary seal shall also meet the following requirements:

A) The secondary seal shall be installed above the primary seal so that it completely covers the space between the roof edge and the vessel wall except as allowed by Condition #02(3).

B) There shall be no holes, tears, or other openings in the seal or seal fabric.

10) §63.120(b)(10)(i) If during the inspections required in Condition #05(6), the primary seal has holes, tears or other openings in the seal or the seal fabric; or the secondary seal has holes, tears or other openings, the operator shall repair the items as necessary so that none of the conditions specified in this subcondition exist before refilling the storage vessel with organic HAP.

11) §63.120(b)(8) The operator shall repair any conditions that do not meet the requirements in Conditions #02(2) and (3) or subconditions (8) and (9), above, no later than forty-five (45) calendar days after identification, or shall empty and remove the storage vessel from service no later than forty-five (45) calendar days after identification. If, during such seal gap measurements or such inspections, a failure is detected that cannot be repaired within forty-five (45) calendar days and if the vessel cannot be emptied within forty-five (45) calendar days, the operator may utilize up to 2 extensions of up to thirty (30) additional calendar days each. The decision to utilize an extension must be documented per Condition #05(2).

#09 §63.642(e) The owner or operator shall keep copies of all applicable reports and records for at least 5 years. All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours. Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche.

24. Points of emissions and limitations

EUG 20: 63.640 (Subpart CC) Group 2 Storage Vessels. Tanks 997 and 998 constructed in 1985; all others constructed before 1970.

Tank #	EU	Point ID
6	20128	Tk6
30	13559	Tk30
41	1356	Tk41
155	13563	Tk155
181	20129	Tk181
189	6350	Tk189
190	6351	Tk190
277	13573	Tk277
279	6364	Tk279
281	13574	Tk281
283	13576	Tk283
312	6368	Tk312
314	6369	Tk314
315	6370	Tk315

Tank #	EU	Point ID
401	6375	Tk401
402	13577	Tk402
403	6376	Tk403
421	13580	Tk421
422	13581	Tk422
434	3684	Tk434
443	13582	Tk433
444	13583	Tk444
696	NA	Tk696
747	6393	Tk747
751	5397	Tk751
997	13588	Tk997
998	13589	Tk998
1070	20126	Tk1070

LIMITATIONS

#01 §63.641 The tanks shall not store liquids with a stored-liquid maximum true vapor pressure greater than or equal to 1.5 psia and stored-liquid annual average true vapor pressure greater than or equal to 1.2 psia and annual average HAP liquid concentration greater than four (4) percent by weight total organic HAP.

MONITORING, RECORDKEEPING, REPORTING

#02 §63.646(b)(2) When the operator and the DEQ do not agree on whether the annual average weight percent organic HAP in the stored liquid is above or below four (4) percent for a storage vessel, EPA Method 18, of 40 CFR 60, Appendix A, (SC#46) shall be used.

#03 §63.654(i)(iv) If a storage vessel is determined to be a Group 2 because the weight percent total organic HAP of the stored liquid is less than or equal to 4 percent, a record of any data, assumptions, and procedures used to make this determination shall be retained.

#04 §63.123(a) The operator shall keep readily accessible records showing the dimensions of the storage vessel and an analysis showing the capacity of the storage vessel. This record shall be kept as long as the storage vessel retains Group 2 status and is in operation.

#05 1) §63.640(l)(ii) If a deliberate operational process change is made to an existing petroleum refining process unit and the change causes a Group 2 emission point to become a Group 1 emission point, as defined in §63.641, then the owner or operator shall comply with the requirements for existing sources for the Group 1 emission point upon initial start-up, unless the owner or operator demonstrates to DEQ that achieving compliance will take longer than making the change. If this demonstration is made to DEQ's satisfaction, the owner or operator shall follow the procedures in Condition #05(2)(A) through (C) to establish a compliance date.

2) §63.640(m) If a change that does not meet the criteria in Condition #05(1) above is made to a petroleum refining process unit and the change causes a Group 2 emission point to become a Group 1 emission point (as defined in §63.641), then the owner or operator shall comply with the requirements for the Group 1 emission point as expeditiously as practicable, but in no event later than 3 years after the emission point becomes Group 1. The owner or operator shall submit a compliance schedule to the DEQ for approval, along with a justification for the schedule.

A) The compliance schedule shall be submitted within 180 days after the change is made, unless the compliance schedule has been previously submitted to the permitting authority. If it is not possible to determine until after the change is implemented whether the emission point has become Group 1, the compliance schedule shall be submitted within 180 days of the date when the affect of the change is known to the source. The compliance schedule may be submitted in the next Periodic Report if the change is made after the date the Notification of Compliance Status report is due.

B) The DEQ shall approve or deny the compliance schedule or request changes within 120 calendar days of receipt of the compliance schedule and justification.

Approval is automatic if not received from the DEQ within 120 calendar days of receipt.

#06 §63.654(g)(7) If a performance test for determination of compliance for an emission point that has changed from Group 2 to Group 1 is conducted during the period covered by a Periodic report, the results of the performance test shall be included in the Periodic Report.

#07 §63.642(e) and §63.654(h)(1) The owner or operator shall keep copies of all applicable reports and records for at least 5 years. All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours. Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche. Records and reports of start-up, shutdown and malfunction are not required if they pertain solely to Group 2 emission points that are not included in an emission average.

25. Points of emissions and limitations

EUG 21: NSPS 60.110b (Subpart Kb) Internal Floating Roof Storage Vessels Storing Volatile Organic Liquids Above 0.75 psia Vapor Pressure, Group 2.

Tank #	EU	Point ID
25	6338	Tk25
1061	13594	Tk1061
1070	20126	Tk1070
1080	NA	Tk1080
782	6402	Tk782

LIMITATIONS

#01 The tanks are subject to 40 CFR 60 Subpart Kb (§60.110b *et seq*) and to OAC 252:100-39-41(a), (b), and (e)(1). Conditions #02 through #12 represent the most stringent provisions of each.

#02 §60.112b(a) The tanks shown in the preceding table shall not store a volatile organic liquid that has a maximum true vapor pressure greater than 11.1 psia.

#03 Three tanks subject to predecessor permit conditions have been released from those conditions and the Kb conditions stated here are considered to have sufficient stringency. The tanks and the permits that contained those conditions are shown following.

Tank No.	Permit No.
782	94-406-O (M-2)
1061	95-262-O (M-1)
1070	99-040-C

MONITORING, RECORDKEEPING, REPORTING

#04 §60.116b(e)(1) Available data on the storage temperature may be used to determine the maximum true vapor pressure based upon the highest expected calendar-month average of the storage temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

#05 §60.116b(e)(2) For crude oil or refined petroleum products the vapor pressure may be obtained by using available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference – see 60.17), unless the DEQ specifically requests that the liquid be sampled, the actual storage temperature determined and the Reid vapor pressure determined from the sample(s).

#06 §60.113b(a)(1) The operator shall visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the storage vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the operator repair the items before filling the storage vessel.

#07 The operator shall visually inspect the internal floating roof and the seal according to the following schedule:

1) §60.113b(a)(2) For vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every twelve (12) months. If the internal floating roof is not resting on the surface of the VOL, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the operator shall repair the items or empty and remove the tank from service within 45 days.

2) §60.113b(a)(4) Visually inspect the internal floating roof and the seal each time the storage vessel is emptied and degassed. These inspections are required at least every 10 years for vessels required to complete annual inspections of Condition #07(1) above, and at least once every 5 years for vessels equipped with a double-seal system that do not complete the annual inspections of Condition #07(1) above. If the internal floating roof has defects, the primary or secondary seal has holes, tears or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than 10 percent open area, the operator shall repair the items as necessary so the none of the conditions exist before refilling the storage vessel with VOL.

#08 1) §60.116b(b) The permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel. This record shall be kept on site or at a local field office for the life of the tank.

2) §60.116b(c) The permittee shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period. These records shall be retained on-site or at a local field office for at least two years after the dates of recording.

#09 40 CFR 60.7(b) requires that the operator shall maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of the air pollution control equipment on these vessels. These records shall be retained in a file for at least two years after the dates of recording.

#10 1) §60.113b(a)(5) Except as provided in subcondition (b) of this condition, for all inspections required for this source, the operator shall notify the DEQ in writing at least thirty (30) calendar days prior to the refilling of each storage vessel to afford the DEQ the opportunity to have an observer present.

2) §60.113b(a)(5) If the inspection required of this source is not planned and the operator could not have known about the inspection thirty (30) days in advance of refilling the vessel, the operator shall notify the DEQ at least seven (7) calendar days prior to the refilling of the storage vessel. Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. Alternately, the notification including the written documentation may be made in writing and sent so that it is received by the DEQ at least seven (7) calendar days prior to refilling.

#11 §60.112b(a)(1) A storage vessel with a fixed roof in combination with an internal floating roof shall meet the following specifications.

1) §60.112b(a)(1)(i) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

2) §60.112b(a)(1)(ii) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof.

A) §60.112b(a)(1)(ii)(A) A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.

B) §60.112b(a)(1)(ii)(B) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.

C) §60.112b(a)(1)(ii)(C) A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

3) §60.112b(a)(1)(iii) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

4) §60.112b(a)(1)(iv) Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

5) §60.112b(a)(1)(v) Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

6) §60.112b(a)(1)(vi) Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.

7) 60.112b(a)(1)(vii) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.

8) §60.112b(a)(1)(viii) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

9) §60.112b(a)(1)(ix) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

#12 §60.115b The owner or operator shall keep records and furnish reports as required by 40 CFR 60.115b(a). Copies of these reports and records shall be kept for at least two years following the date on which they were made. The owner or operator shall meet the following requirements.

1) §60.115b(a)(2) Keep a record of each inspection required by 40 CFR 60.113b. Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, floating roof, and fittings).

2) §60.115b(a)(4) After each inspection required by 40 CFR 60.113b that finds holes or tears in the seal or seal fabric, or defects in the internal roof, or other control equipment defects listed in 40 CFR 60.113b, a report shall be furnished to Air Quality within 30 days of the inspection. The report shall identify the storage vessel, the reason it did not meet the specifications of §§61.112b(a)(1) or 60.113b(a)(3), and each repair made.

26. Point of emissions, and limitations

EUG 22: NSPS 60.110b (Subpart Kb) External Floating Roof Storage Vessel Storing VOL Above 0.75 psia Vapor Pressure.

Tank #	EU	Point ID
583	13591	Tk583

LIMITATIONS

#01 This tank had been subject to conditions under predecessor permit 94-136-O, from which it has been released. The Kb conditions stated here are considered to have sufficient stringency. The tank is subject to 40 CFR 60 Subpart Kb (§60.110b *et seq*) and to OAC 252:100-39-41(a), (b), and (e)(1). Conditions #02 through #08 represent the most stringent provisions of each.

#02 1) §60.112b(a) The tank may not store VOCs that have a true vapor pressure that exceeds 11.1 psia.

2) §60.113b(b)(4)(i) The accumulated areas of gaps between the vessel wall and the primary seal, as calculated according to subcondition #05(3), shall not exceed 10 square inches per foot of vessel diameter, and the width of any portion of any gap shall not exceed 1.5 inches.

3) §60.113b(b)(4)(ii)(B) The accumulated area of gaps between the vessel wall and the secondary seal, as determined by subcondition #05(4), below, shall not exceed 1.0 square inch per foot of vessel diameter and the width of any portion of any gap shall not exceed 0.5 inches. These seal gap requirements may be exceeded during the measurement of primary seal gaps.

MONITORING, RECORDKEEPING, REPORTING

#03 §60.116b(e)(1) Available data on the storage temperature may be used to determine the maximum true vapor pressure based upon the highest expected calendar-month average of the storage temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

#04 §60.116b(e)(2) For crude oil or refined petroleum products the vapor pressure may be obtained by using the available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference – see §60.17), unless the DEQ specifically requests that the liquid be sampled, the actual storage temperature determined and the Reid vapor pressure determined from the sample(s).

#05 1) §60.113b(b)(1) The operator shall determine the gap areas and maximum gap widths between the primary seal and the wall of the storage vessel, and the secondary seal and the wall of the storage vessel according to the following frequency.

A) §60.113b(b)(1)(i) Measurements of gaps between the vessel wall and the primary seal shall be performed at least once every five (5) years.

B) §60.113b(b)(1)(ii) Measurements of gaps between the vessel wall and the secondary seal shall be performed at least once per year.

C) §60.113b(b)(1)(iii) If any storage vessel ceases to store VOL for a period of one (1) year or more, measurements of gaps between the vessel wall and the primary seal, and the gaps between the vessel wall and the secondary seal shall be performed within sixty (60) calendar days of the vessel being refilled with VOL.

2) §60.113b(b)(2) The operator shall determine gap widths and gap areas in the primary and secondary seals (seal gaps) individually by the procedures described in subconditions (A), (B), and (C), below.

A) §60.113b(b)(2)(i) Seal gaps, if any, shall be measured at one or more floating roof levels when the roof is not resting on the roof leg supports.

B) §60.113b(b)(2)(ii) Seal gaps, if any, shall be measured around the entire circumference of the vessel in each place where a one-eighth (1/8) inch diameter uniform probe passes freely (without forcing or binding against the seal) between the seal and the wall of the storage vessel. The circumferential distance of each such location shall also be measured.

C) §60.113b(b)(2)(iii) The total surface area of each gap described in subcondition (2)(B), above, shall be determined by using probes of various widths to measure accurately the actual distance from the vessel wall to the seal and multiplying each such width by its respective circumferential distance.

3) §60.113b(b)(3) The operator shall add the gap surface area of each gap location for the primary seal and divide the sum by the nominal diameter of the vessel.

4) §60.113b(b)(3) The operator shall add the gap surface area of each gap location for the secondary seal and divide the sum by the nominal diameter of the vessel.

5) §60.113b(b)(6) The operator shall visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

6) §60.113b(b)(2) Within 60 days of performing the seal gap measurements required by Condition #05(1), the operator shall furnish DEQ with a report that contains:

A) the date of the measurement;

B) the raw data obtained in the measurement; and

C) the calculations described in Condition #05(2, 3, and 4).

7) §60.113b(b)(3) The owner shall keep a record of each gap measurement performed as required by Condition #05(1). Each record shall identify the storage vessel in which the measurement was performed and shall contain the data in subcondition (6) above. These records shall be maintained for a period of two years from date of recording.

#06 1) §60.7(f) As specified in 40 CFR 60.7(f), any owner or operator subject to the provisions of NSPS shall maintain a file of all measurements and all other information required by this part recorded in a permanent file suitable for inspection. This file shall be retained for at least two years following the date of such measurements, maintenance and records.

A) §60.116b(b) The permittee shall keep readily accessible records showing the dimensions of the storage vessels and an analysis showing the capacity of the vessels. This record shall be kept for the life of the source.

B) The permittee shall maintain a record for Tank No. 583 of the cumulative annual throughput, the volatile organic liquid stored, the period of storage and the maximum true vapor pressure of that VOL during the respective storage period. Copies of these records shall be retained on location for at least two years after the dates of recording.

C) §60.7(b) The permittee shall maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of the air pollution control equipment on these vessels. These records shall be retained in a file for at least two years after the dates of recording.

2) §60.113b(b)(4)(iii) If the operator utilizes the extension specified in Condition #08(11), of this source, the operator shall document the decision. Documentation of a decision to utilize the extension shall include: a description of the failure, document that alternate storage capacity is unavailable, and specify a schedule of actions that will ensure that the control equipment will be repaired or the vessel will be emptied, as soon as practical.

3) The operator shall keep a record of each inspection performed as required by #03 (1). Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component or the control equipment.

#07 1) §60.113b(b)(6)(ii) Except as provided in subcondition (2), below, for all the inspections required by Condition #05(5), the operator shall notify the DEQ in writing at least thirty (30) calendar days prior to the refilling of each storage vessel with VOL to afford the DEQ the opportunity to inspect the storage vessel prior to refilling.

2) §60.113b(b)(6)(ii) If the inspection required by Condition #05(5), above, is not planned and the operator could not have known about the inspection thirty (30) calendar days in advance of refilling the vessel with organic HAP, the operator shall notify the DEQ at least seven (7) calendar days prior to refilling of a storage vessel. Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. Alternately, the notification including the written documentation may be made in writing and sent so that it is received by the DEQ at least seven (7) calendar days prior to refilling.

3) §60.113b(b)(5) The operator shall notify the DEQ in writing thirty (30) calendar days in advance of any gap measurements required by Condition #05, above, to afford the DEQ the opportunity to have an observer present.

4) §60.115b(b)(4) If seal gaps in exceedance of Condition #02(2) and (3), above, are found during the inspections required by Condition #05(1) or if the specification in Conditions #08(8) and (9) are not met, the operator shall report the following information to the DEQ within 30 days of the inspection.

A) Date of the seal gap measurement.

B) The raw data obtained in the seal gap measurement and the calculations described in Conditions #05(3) and (4).

C) Description of the nature of and date the repair was made, or the date the storage vessel was emptied.

#08 1) §60.112b(a)(2)(iii) The external floating roof shall be floating on the liquid surface at all times except when the floating roof must be supported by the leg supports during the following periods.

A) During the initial fill.

B) When the vessel is completely emptied before being subsequently refilled.

2) §60.112b(a)(2)(iii) When the floating roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

3) §60.112b(a)(2)(i) Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device must meet the following criteria.

A) §60.112b(a)(2)(i) Consist of two seals, one above the other.

B) §60.112b(a)(2)(i)(A) The primary seal shall be either a metallic shoe seal or a liquid-mounted seal.

4) §60.112b(a)(2)(i) Except as allowed in Condition #02(2) and (3), both the primary and secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion.

5) §60.112b(a)(2)(ii) Automatic bleeder vents are to be closed at all times when the roof is floating, except when the roof is being floated off or is being landed on the roof leg supports.

6) §60.112b(a)(2)(ii) Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except with the device is in actual use.

7) §60.112b(a)(2)(ii) Rim vents are to be set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting.

8) The primary seal shall also meet the following requirements.

A) §60.113b(b)(4)(i)(A) Where a metallic shoe seal is in use, one end of the metallic shoe shall extend into the stored liquid and the other end shall extend a minimum vertical distance of 24 inches above the stored liquid surface.

B) §60.113b(b)(4)(i)(B) There shall be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

9) §60.113b(b)(4)(ii) The secondary seal shall also meet the following requirements.

A) §60.113b(b)(4)(ii)(A) The secondary seal shall be installed above the primary seal so that it completely covers the space between the roof edge and the vessel wall except as provided by Condition #05(2).

B) §60.113b(b)(4)(ii)(C) There shall be no holes, tears, or other openings in the seal or seal fabric.

10) §60.113b(b)(6)(i) If during the inspections required in Condition #05(5), the primary seal has holes, tears or other openings in the seal or the seal fabric; or the secondary seal has holes, tears or other openings, the operator shall repair the items as necessary so that none of the conditions specified in this subcondition exist before refilling the storage vessel with VOL.

11) §60.113b(b)(4)(iii) The operator shall repair any conditions that do not meet the requirements in Conditions #02(2) and (3) or subconditions (8) and (9), above, no later than forty-five (45) calendar days after identification, or shall empty the storage vessel. If a failure is detected that cannot be repaired within forty-five (45) calendar days and if the vessel cannot be emptied within forty-five (45) calendar days, a 30-day extension may be requested from DEQ in the inspection report required by #07(4). Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

27. Point of emissions, and limitations

EUG 23: NSPS 60.110b Subpart Kb tanks Storing Volatile Organic Liquids (VOL) Below 0.507 psia Vapor Pressure.

CD	Tank #	EU	Point ID
2010	27	13588	Tk27
1917	84	NA	Tk84
1917	85	NA	Tk85
2009	405	6377	Tk405
2009	406	13578	Tk406
1985	997	13588	Tk997
1985	998	13589	Tk998
1987	1002	6406	Tk1002
1989	1005	NA	Tk1005
1990	1012	15950	Tk1012
1993	1039	16561	Tk1039

LIMITATIONS

#01 60.110b(b) The operator shall not store VOL with a true vapor pressure that exceeds or equals 0.507 psia.

#02 Tanks 84 and 85 were rehabilitated and modified under construction Permit No. 99-355-C, issued March 24, 2000. The permit authorized VOC emissions of 0.037 TPY for each tank and limited throughput to 3.02 million gallons per year for each tank.

MONITORING, RECORDKEEPING, REPORTING REQUIREMENTS.

#03 60.116b(a) The owner or operator shall keep copies of all records required by this section for at least 5 years, except for the record required by 60.116b(b), concerning dimensions of the storage vessels and an analysis showing the capacity of the vessels. This record shall be kept for the life of the tanks.

#03 A copy of these records shall be retained on-site or at a local field office for at least five years after the dates of recording. The following records shall be made available to regulatory personnel upon request.

1) Volatile organic liquid stored in the tanks, the period of storage and the maximum true vapor pressure of that VOL during the respective storage period
2) Total throughput of wax (monthly and cumulative annual).
3) Test results of any leak detection and repair program carried out per NSPS Subpart VV.

28. Points of emissions and limitations

EUG 24: NSPS 60.110a Storage Vessels Storing Petroleum Liquids Below 1.0 psia Vapor Pressure

CD	Tank #	EU	Point ID
1980	224	13569	Tk224
1988	277	13573	Tk277
1979	881	NA	Tk881
1983	890	NA	Tk890
1982	992	NA	Tk992
1982	993	NA	Tk993

LIMITATIONS

#01 Storage vessels that are of the capacity identified in §60.110a(a) and that are constructed after May 18, 1978, and before July 23, 1984, and storing petroleum liquids with true vapor pressure (TVP) less than 1.5 psia are exempt from the standards of §60.112a, from the testing and procedures of §60.113a, and from the alternative limitations of §60.114a. Further, vessels storing liquids with TVP less than 1.0 psia are exempt from the monitoring requirements of §60.115a. Thus, the only requirement for this EUG is that the operator shall not store petroleum liquids with a true vapor pressure that exceeds 1.0 psia.

MONITORING, RECORDKEEPING, REPORTING

#02 None.

29. Points of emissions and limitations

EUG 25: NSPS 60.110 (Subpart K) Storage Vessels Storing Petroleum Liquids Below 6.9 kPa Reid Vapor Pressure (1.0 psia)

CD	Tank #	EU	Point ID
1974	152	6324	Tk152
1973	158	13565	Tk158
1977	468	NA	Tk468
1978	472	NA	Tk472
1976	983	NA	Tk983
1976	984	NA	Tk984
1976	985	NA	Tk985
1976	986	NA	Tk986
1976	987	NA	Tk987

LIMITATIONS
#01 Storage vessels that are of the capacity identified in §60.110 and that are constructed after June 11, 1973, and before May 19, 1978, and storing petroleum liquids with true vapor pressure (TVP) less than 1.5 psia are exempt from the VOC standards of §60.112. Further, vessels storing liquids with TVP less than 1.0 psia are exempt from the monitoring requirements of §60.113. Thus, the only requirement for this EUG is that the operator shall not store petroleum liquids with a true vapor pressure that exceeds 1.0 psia.

MONITORING, RECORDKEEPING, REPORTING
#02 None.

30. Point of emissions, and limitations

EUG 26: Internal Floating Roof Storage Vessels Subject to OAC 252:100-39-41.

CD	Tank #	EU	Point ID
1922	432	1591	Tk432
1923	433	6383	Tk433
1953	435	6385	Tk435

LIMITATIONS
#01 The operator may not store VOCs that have a vapor pressure of 11.1 psia or greater under actual storage conditions.
[OAC 252:100-37-15(a)(1) and OAC 252:100-39-41(a)(1)]
#02 Each VOC storage vessel with a capacity of 400 gal (1.5 m^3) or more shall be equipped with a permanent submerged fill pipe.
[OAC 252:100-37-15(b) and OAC 252:100-39-41(b)]

MONITORING, RECORDKEEPING, REPORTING REQUIREMENTS:

#03 Visually inspect the internal floating roof and the seal through manholes and roof hatches on the fixed roof at least once every twelve (12) months.
[OAC 252:100-8-6(a)(3)(A)(ii)]

1) There are no visible holes, tears, or other openings in the seal(s) or seal fabric.

2) The seal(s) are intact and uniformly in place around the circumference of the floating roof between the floating roof and the vessel wall.

#04 Copies of inspections required by #03 shall be retained by the operator for a minimum of two (2) years and be made available to the Division Director, upon request, at any reasonable time. [OAC 252:100-8-6(a)(3)(A)(ii)]

#05 1) Each vessel shall be equipped with a fixed roof with an internal-floating cover.

2)The cover shall rest on the surface or the liquid contents at all times (i.e. off the leg supports), except during initial fill, when the storage vessel is completely empty or during refilling.

3)When the cover is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

4)The floating roof shall be equipped with a closure seal, or seals, to close the space between the cover edge and vessel wall.

5)All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place. [OAC 252:100-39-41(a)(1)]

#06 Other equipment or methods that are of equal efficiency for purposes of air pollution control may be used when approved by the Division Director and in concert with federal guidelines. [OAC 252:100-39-41(a)(3)]

31. Point of emissions and limitations **[OAC 252:100-8-6(a)]**

EUG 27: External Floating Roof Storage Vessels Subject to OAC 252:100-39-41. (previously listed in group 2 tanks)

CD	Tank #	EU	Point ID
1957	314	6369	Tk314

LIMITATIONS

#01 The operator shall not store VOCs that have a vapor pressure of 11.1 psia or greater under actual storage conditions.
[OAC 252:100-37-15(a)(1) and OAC 252:100-39-41(a)(1)]

#02 Although OAC:100-39-41 and 100-37 do not specify inspection frequency or recordkeeping requirements, inspections shall be performed annually.

#03 Each VOC storage vessel with a capacity of 400 gal (1.5 m^3) or more shall be equipped with a permanent submerged fill pipe.
[OAC 252:100-37-15(b) and OAC 252:100-39-41(b)]

MONITORING, RECORDKEEPING, REPORTING

#04 There shall be no visible holes, tears, of other openings in the seal(s) or seal fabric.
[OAC 252:100-39-30(c)(1)(B)(i)]

#05 The operator shall perform semi-annual inspections to determine compliance with #04. [OAC 252:100-39-30(c)(2)(A)]

#06 Operator shall retain copies of all records for a minimum of two (2) years after the date on which the record was made and shall be made available to the Division Director, upon request, at any reasonable time. [OAC 252:100-39-30(c)(3)]

32. Points of emissions and limitations

EUG 28: Cone Roof Tanks

All of these tanks were constructed before the applicability date of any rules and contain liquids with vapor pressure below any of the thresholds necessary to make the tanks subject to any state rules affecting "existing" tanks.

EU	Point ID	EU	Point ID	EU	Point ID
20127	Tk1	Tk79	Tk79	Tk264	Tk264
Tk9	Tk9	Tk80	Tk80	Tk265	Tk265
Tk10	Tk10	Tk81	Tk81	Tk266	Tk266
Tk11	Tk11	Tk83	Tk83	Tk267	Tk267
6334	Tk15	Tk132	Tk132	Tk271	Tk271
6335	Tk16	Tk133	Tk133	6363	Tk272
Tk23	Tk23	Tk134	Tk134	Tk273	Tk273
Tk26	Tk26	6344	Tk151	Tk274	Tk274
20130	Tk28	13564	Tk156	Tk275	Tk275
6339	Tk29	14307	Tk157	Tk276	Tk276
Tk33	Tk33	15944	Tk159	6364	Tk279
Tk34	Tk34	Tk192	Tk192	6356	Tk280
6342	Tk35	15945	Tk193	6366	Tk284
6343	Tk36	13567	Tk194	Tk305	Tk305
Tk38	Tk38	Tk195	Tk195	Tk317	Tk317
Tk45	Tk45	Tk196	Tk196	Tk318	Tk318
Tk46	Tk46	6355	Tk215	Tk319	Tk319
Tk52	Tk52	15946	Tk217	Tk320	Tk320
Tk53	Tk53	13568	Tk218	Tk321	Tk321
Tk54	Tk54	Tk223	Tk223	Tk322	Tk322
Tk62	Tk62	Tk227	Tk227	6371	Tk323
Tk65	Tk65	Tk228	Tk228	Tk327	Tk327
Tk66	Tk66	Tk229	Tk229	Tk328	Tk328
Tk68	Tk68	Tk232	Tk232	Tk329	Tk329
Tk69	Tk69	Tk233	Tk233	Tk331	Tk331
Tk71	Tk71	Tk234	Tk234	Tk332	Tk332
Tk72	Tk72	Tk235	Tk235	Tk335	Tk335
Tk73	Tk73	Tk236	Tk236	Tk390	Tk390
Tk74	Tk74	Tk237	Tk237	Tk391	Tk391
Tk75	Tk75	Tk240	Tk240	Tk392	Tk392
Tk76	Tk76	Tk252	Tk252	Tk393	Tk393

EU	Point ID
Tk394	Tk394
Tk396	Tk396
Tk397	Tk397
6373	Tk398
6374	Tk399
6377	Tk404
6379	Tk407
6380	Tk412
6381	Tk413
6386	Tk445
Tk471	Tk471
Tk509	Tk509
6389	Tk510
6390	Tk511
6391	Tk519
Tk645	Tk645
Tk646	Tk646
Tk649	Tk649
Tk650	Tk650
Tk675	Tk675
Tk691	Tk691
Tk692	Tk692
Tk693	Tk693
Tk694	Tk694
Tk700	Tk700
13585	Tk701
13584	Tk702
6403	Tk799
Tk800	Tk800
15958	Tk801
13586	Tk802
15949	Tk803
Tk807	Tk807
Tk828	Tk828
Tk829	Tk829
Tk830	Tk830
Tk831	Tk831
Tk835	Tk835
6404	Tk838
Tk847	Tk847
Tk848	Tk848
Tk851	Tk851
Tk852	Tk852
Tk853	Tk853

EU	Point ID
Tk854	Tk854
Tk855	Tk855
Tk856	Tk856
Tk857	Tk857
Tk861	Tk861
Tk865	Tk865
Tk867	Tk867
13587	Tk870
Tk875	Tk875
Tk876	Tk876
Tk877	Tk877
Tk878	Tk878
Tk879	Tk879
Tk880	Tk880
Tk882	Tk882
Tk883	Tk883
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Tk887	Tk887
Tk888	Tk888
Tk891	Tk891
Tk893	Tk893
Tk898	Tk898
Tk913	Tk913
Tk914	Tk914
Tk916	Tk916
Tk918	Tk918
Tk921	Tk921
Tk922	Tk922
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Tk927	Tk927
Tk928	Tk928
Tk929	Tk929
Tk930	Tk930
Tk931	Tk931
Tk932	Tk932
Tk933	Tk933
Tk934	Tk934
Tk935	Tk935
Tk936	Tk936

EU	Point ID
Tk937	Tk937
Tk938	Tk938
Tk939	Tk939
Tk940	Tk940
Tk941	Tk941
Tk942	Tk942
Tk943	Tk943
Tk944	Tk944
Tk955	Tk955
TkAGT1	TkAGT1
TkAGT2	TkAGT2
TkAGT3	TkAGT3
TkAGT4	TkAGT4

LIMITATIONS
None.

MONITORING, RECORDKEEPING, REPORTING
#01 Records sufficient to demonstrate that these tanks contain liquids with vapor pressure below any applicable standard shall be maintained. Such records shall be sufficient to demonstrate that each tank remains a Group 2 tank under 40 CFR 63 Subpart CC.

33. Points of emissions and limitations

EUG 29: Pressurized Spheres containing VOC with vapor pressure > 11.1 psia

Tank #	EU	Point ID
Tk 585	NA	Tk585
Tk 586	NA	Tk586
Tk 587	NA	Tk587
Tk 588	NA	Tk588
Tk 589	NA	Tk589
Tk 788	NA	Tk788
Tk 789	NA	Tk789
Tk 797	NA	Tk797
Tk 798	NA	Tk798
Tk 804	NA	Tk804
Tk 805	NA	Tk805
Tk 806	NA	Tk806

LIMITATIONS
None. These vessels predate most federal and state rules and regulations. Since they are pressurized, they satisfy the requirements of OAC 252:100-39-41. Pressurized vessels do not meet the definition of storage vessels in MACT CC, per 40 CFR 63.641.

MONITORING, RECORDKEEPING, REPORTING
None.

34. Point of emissions and limitations

EUG 30: Pressurized Bullet Tanks containing VOC with vapor pressure > 11.1 psia

Tank #	EU	Point ID
Tk 1007	NA	Tk1007
Tk 1008	NA	Tk1008
Tk 791	NA	Tk 791
Tk 792	NA	Tk 792
Tk 793	NA	Tk 793
Tk 794	NA	Tk 794
Tk 795	NA	Tk 795

LIMITATIONS
None. These vessels predate most federal and state rules and regulations. Since they are pressurized, they satisfy the requirements of OAC 252:100-39-41. Pressurized vessels do not meet the definition of storage vessels in MACT CC, per 40 CFR 63.641.

MONITORING, RECORDKEEPING, REPORTING
None.

35. Point of emissions and limitations

EUG 31: Underground LPG Cavern (pseudo pressure vessel)

CD	Tank #	EU	Point ID
1961	Tk 900	NA	Tk900

LIMITATIONS
None. This "vessel" predates federal and state rules and regulations. Since it is pressurized, it satisfies the requirements of OAC 252:100-39-41. Pressurized vessels do not meet the definition of storage vessels in MACT CC, per 40 CFR 63.641.

MONITORING, RECORDKEEPING, REPORTING
None.

36. Points of emissions

EUG 32: Non-gasoline Loading Racks

EU	Equipment Point ID	Installed Date
NA	Black Oil Loading Rack	1937
NA	Extract Truck Loading Rack	1993
NA	Extract Rail Loading Rack	1930
NA	Wax Truck Loading Rack	1979
NA	Wax Rail Loading Rack	1917
NA	LOB Rail Loading Rack	1967
NA	LOB Truck Loading Rack	1978
NA	Resid Truck Loading Rack	1962
NA	Diesel Rail Loading Rack	1986
NA	Coke Truck Loading Area	1991

LIMITATIONS
None.

MONITORING, RECORDKEEPING, REPORTING
None.

37. Points of emissions

EUG 33: LPG Loading Racks

EU	Equipment Point ID	Installed Date
NA	LPG Rail Loading Rack	1917
NA	LPG Truck Loading Rack	1956

LIMITATIONS
When loading is by means other than hatches, all loading and vapor lines shall be equipped with fittings that make vapor-tight connections and which close automatically when disconnected per OAC 252:100-39-41(c)(4).

MONITORING, RECORDKEEPING, REPORTING
In addition to those requirements contained in 252:100-39-41(c), stationary loading facilities shall be checked annually in accordance with EPA Test Method 21, Leak Test. Leaks greater than 5,000 ppmv shall be repaired within 15 days. Facilities shall retain inspection and repair records for at least two years.

38. Points of emissions

EUG 34: Cooling Towers

EU	Point ID	Equipment
15942	CT2	LEU/MEK Cooling Tower
15942	CT3	Coker/#2 Platformer Cooling Tower
15942	CT4	LEU/MEK Cooling Tower
15942	CT6	PDA/#5 BH Cooling Tower
15942	CT8	CDU Cooling Tower
15942	CT9	BSU Cooling Tower

LIMITATIONS
#01 Cooling towers are trivial sources under Part 70 and are not subject to limitations.

MONITORING, RECORDKEEPING, and REPORTING
#02 None.

39. Points of emissions

EUG 35: Oil/Water Separators Subject to OAC 252:100-37-37 and 39-18

EU	Point ID	Equipment	Installed Date
NA	D-40	Separator at Lube Packaging	Before 7/1/72
NA	D-41	Separator at Lube Blending and Tankage	Before 7/1/72
NA	D-42	Separator from MEK/Lube Unit	Before 7/1/72
NA	S1-51	Separator at Belt Press (sealed)	1985

EU	Point ID	Equipment	Installed Date
6332	Tk 532	Separator at T&S (sealed)	Before 7/1/72
6331	Tk 533	Separator at T&S (sealed)	Before 7/1/72

LIMITATIONS

#01 A single-compartment or multiple-compartment VOC/water separator that receives effluent water containing 200 gals/d (760 l/d) or more of any VOC from any equipment processing, refining, treating, storing or handling VOCs shall be equipped such that the container totally encloses the liquid contents and all openings are sealed. All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place. The oil removal devices shall be gas-tight except when manual skimming, inspection and/or repair is in progress. [OAC 252:100-37-37 (1) and OAC 252:100-39-18(b)(1)]

MONITORING, RECORDKEEPING, REPORTING

None.

40. Points of emissions and limitations

EUG 36: Spark Ignition Internal Combustion Engines Subject to 40 CFR Part 63 Subpart ZZZZ

EU #	Equipment Point ID	HP	Equip #	Make	Installed Date
257	#3 CT Circulation Pump	615	EG-5152		
256	#6 CT Circulation Pump	650	EG-5156		
208	Unifiner H2 Recycle Comp	330	C-2719	Ingersoll	1957
241	PDA Propane Comp	392	EG-5747	Waukesha	1980
254	#2 CT Spray Pump Eng	295	EG-6348	Caterpillar	1990
255	#2 CT Circ Pump Engine	465	EG-5579	Caterpillar	1977
258	#6 CT Spray Pump	245	EG-5154	Caterpillar	1971
	Emergency	45	EG-6349		
	Emergency	69	EG-5879		
	Emergency	175	EG-6235		

#01 No initial notification is necessary for these emergency engines. [63.6590(b)(3)]

#02 The owner/operator shall comply with all applicable requirements of the NESHAP: Reciprocating Internal Combustion Engines, Subpart ZZZZ, for each affected facility, by October 20, 2013, including but not limited to:

What This Subpart Covers

a. § 63.6580 What is the purpose of subpart ZZZZ?
b. § 63.6585 Am I subject to this subpart?
c. § 63.6590 What parts of my plant does this subpart cover?
d. § 63.6595 When do I have to comply with this subpart?

Emission and Operating Limitations

e. § 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary CI RICE located at an area source of HAP emissions?

f. § 63.6604 What fuel requirements must I meet if I own or operate an existing stationary CI RICE?

General Compliance Requirements

g. § 63.6605 What are my general requirements for complying with this subpart?

Testing and Initial Compliance Requirements

h. § 63.6615 When must I conduct subsequent performance tests?
i. § 63.6620 What performance tests and other procedures must I use?
j. § 63.6625 What are my monitoring, installation, operation, and maintenance requirements?
k. § 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?

Continuous Compliance Requirements

l. § 63.6635 How do I monitor and collect data to demonstrate continuous compliance?
m. § 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

Notifications, Reports, and Records

n. § 63.6645 What notifications must I submit and when?
o. § 63.6650 What reports must I submit and when?
p. § 63.6655 What records must I keep?
q. § 63.6660 In what form and how long must I keep my records?

Other Requirements and Information

r. § 63.6665 What parts of the General Provisions apply to me?
s. § 63.6670 Who implements and enforces this subpart?
t. § 63.6675 What definitions apply to this subpart?

41. Points of emissions and limitations

EUG 37: Heaters Subject to only State Requirements

CD	**EU**	**Point ID**
1961	202	CDU H-2
1961	203	CDU H-3
1963	243N	LEU H-102 North
1963	243S	LEU H-102 South

LIMITATIONS

#01 OAC 252:100-19-4. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C. A one-time compliance demonstration is listed in Specific Condition #46 of these Conditions.

MONITORING, RECORDKEEPING, and REPORTING

#02 The facility shall maintain records that show compliance with OAC 252:100-19-4.

42. Points of emissions and limitations

EUG 38: Compression Ignition Internal Combustion Engines Subject to 40 CFR 63 Subpart ZZZZ

Engine Number	HP	USE	Fuel
EG 6217	603	Emergency	Diesel
EG 6218	603	Emergency	Diesel
EG 6312	603	Emergency	Diesel
EG 6289	603	Emergency	Diesel
EG 6290	603	Emergency	Diesel
EG 6472	170	Emergency	Diesel
EG 5886	363	Emergency	Diesel
EG 6031	290	Emergency	Diesel
EG 6522	330	Emergency	Diesel

LIMITATIONS, MONITORING, RECORDKEEPING, and REPORTING

#01 No initial notification is necessary for these emergency engines. [63.6590(b)(3)]

#02 The owner/operator shall comply with all applicable requirements of the NESHAP: Reciprocating Internal Combustion Engines, Subpart ZZZZ, for each affected facility, by May 3, 2013, including but not limited to:

<u>What This Subpart Covers</u>

a. § 63.6580 What is the purpose of subpart ZZZZ?
b. § 63.6585 Am I subject to this subpart?
c. § 63.6590 What parts of my plant does this subpart cover?
d. § 63.6595 When do I have to comply with this subpart?

<u>Emission and Operating Limitations</u>

e. § 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary CI RICE located at an area source of HAP emissions?
f. § 63.6604 What fuel requirements must I meet if I own or operate an existing stationary CI RICE?

<u>General Compliance Requirements</u>

g. § 63.6605 What are my general requirements for complying with this subpart?

<u>Testing and Initial Compliance Requirements</u>

h. § 63.6615 When must I conduct subsequent performance tests?
i. § 63.6620 What performance tests and other procedures must I use?
j. § 63.6625 What are my monitoring, installation, operation, and maintenance requirements?
k. § 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?

<u>Continuous Compliance Requirements</u>

l. § 63.6635 How do I monitor and collect data to demonstrate continuous compliance?
m. § 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

Notifications, Reports, and Records

n. § 63.6645 What notifications must I submit and when?
o. § 63.6650 What reports must I submit and when?
p. § 63.6655 What records must I keep?
q. § 63.6660 In what form and how long must I keep my records?

Other Requirements and Information

r. § 63.6665 What parts of the General Provisions apply to me?
s. § 63.6670 Who implements and enforces this subpart?
t. § 63.6675 What definitions apply to this subpart?

43. INSIGNIFICANT ACTIVITIES

1. Space heaters, boilers, process heaters, and emergency flares less than or equal to 5 MMBtu/hr heat input (commercial natural gas).

A list shall be maintained on-site.

2. Stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or diesel fuel which are either used exclusively for emergency power generation or for other emergency purposes, back-up purposes, and other purposes not part of normal operations service not exceeding 500 hours/year. The current engines will be insignificant sources until the compliance dates outlined in NESHAP Subpart ZZZZ.

MONITORING, RECORDKEEPING, REPORTING

#01 The facility shall maintain a record of the 12-month rolling total of the hours of operation for each piece of equipment included on the emergency power generation list.

#02 Any equipment added to the emergency power generation list will be disclosed to DEQ in writing within 30 working days after the equipment is put into operation.

3. Emissions from stationary internal combustion engines rated less than 50 hp output.

A list shall be maintained on-site.

4. Cold degreasing operations utilize solvents that are denser than air, have a low vapor pressure and produce negligible emissions.

MONITORING, RECORDKEEPING, REPORTING

#01 For each designated piece of equipment the facility shall maintain on file a record, such as an MSDS, showing the name of the solvent used and a record of the solvent density.

5. Non-commercial water washing operations (less than 2,250 barrels/year) and drum crushing operations of empty barrels less than or equal to 55 gallons with less than three percent by volume of residual material.

MONITORING, RECORDKEEPING, REPORTING

#01 The facility shall maintain a record of the 12-month rolling total number of barrels washed.

#02 The facility shall develop and implement a standard operating procedure to ensure the residual material in drums < 55 gallons is less than 3 percent by volume of residual material.

6. Hazardous waste and hazardous materials drum staging areas.

7. Hydrocarbon contaminated soil aeration pads utilized for soils excavated at the facility only.

8. Exhaust systems for chemical, paint, and/or solvent storage rooms or cabinets, including hazardous waste satellite (accumulation) areas.

9. Hand wiping and spraying of solvents from containers with less than 1 liter capacity used for spot cleaning and/or degreasing in ozone attainment areas

10. Additions or upgrades of instrumentation or control systems that result in emissions increases less than the pollutant quantities specified in 252:100-8-3(e)(1).

11. Emissions from fuel storage/dispensing equipment operated solely for facility owned vehicles if fuel throughput is not more than 2,175 gallons/day, averaged over a 30-day period.

MONITORING, RECORDKEEPING, REPORTING

#01 Maintain a record of the 30-day rolling average facility owned vehicle dispensed fuel amount.

12. Emissions from the operation of groundwater remediation wells including but not limited to emissions from venting, pumping, and collecting activities subject to limits for HAPS (§112(b) of CAAA90).

MONITORING, RECORDKEEPING, REPORTING

#01 A list of all equipment shall be maintained on-site.

13. Emissions from storage tanks constructed with a capacity less than 39,894 gallons which store VOC with a vapor pressure less than 1.5 psia at maximum storage temperature.

MONITORING, RECORDKEEPING, REPORTING

#01 The facility shall maintain a record on-site.

44. The Permit Shield is identified in the Standard Conditions, Section VI. Permittee waives the extensive listing required by VI(B). [OAC 252:100-8-6(d)(2)]

45. The drain rate of the LERU Caustic Scrubber system to the sewer shall not exceed 14 barrels per day and shall not exceed 75 gallons in any two-hour period. Records showing the amount drained hourly during each episode of draining shall be maintained. [Consent Order 98-294]

46. APPENDIX

Demonstration of Compliance: OAC 252:100-19-4 (Particulate Matter Emissions from Fuel-Burning Units)

Following is a one time compliance demonstration, based on AP-42 factors, that the fuel-burning units listed in EUG 1, EUG 2, EUG 3, EUG 4, EUG 5, EUG 6, and EUG 37 do not cause a normal exceedance of this subchapter.

Individual pieces of fuel-burning equipment at the facility burn either refinery fuel gas (RFG) or commercial grade natural gas (or its equal). No liquid or solid or other non-gaseous type of fuel is used in any fuel-burning unit. RFG is a mixture of various process unit light gases that contain hydrogen (non-particle emitting) and methane through butane light hydrocarbons. RFG is dry gas, free of liquid particles due to liquid knockout collection drums prior to final fuel end use. Dry gas is recognized by EPA to be at least as clean burning, as to particulates, as commercial grade natural gas. Since AP-42 has no distinct factor for dry gas mixtures, the following demonstrations are based on the natural gas factors.

Boilers and Process Heaters:
Table 1.4-2 of AP-42 lists Total PM emission factor for equipment burning natural gas as 7.6 lbs/10^6ft^3. Since PM emissions using this factor are inversely proportional to the gas heating value, the most conservative PM emission factor is calculated using the heating value for RFG, which is 584 Btu/scf (versus about 1,020 Btu/scf for natural gas), based on 1996 weekly samplings selecting the facility area with the lowest Btu value gas (drum 3213 at No. 1 Platformer Unit), hence:

Total PM, lbs/MMBtu = 7.6 lb/10^6 ft^3 $\times$ ft^3/584 Btu $\times$ 10^6 Btu/MMBtu = 0.013 lb PM/MMBtu

This conservative result is still a factor of 10 below the 0.10 lbs/MMBtu most restrictive maximum allowance specified at 252:100-19-4 Appendix C for source sizes encompassing the facility's fuel-fired boilers and heaters.

Reciprocating Engines
AP-42 Section 3.2.3.3 states that particulate emissions with gas-fired turbines and reciprocating engines are non-detectable with conventional protocols unless the engines are operating in a sooting condition. Normal operation for the facility's gas-fired engines is in the non-sooting mode.

47. TESTING

Within 60 days of achieving maximum firing rate from boiler #10, not to exceed 180 days from initial startup, and at other such times as directed by Air Quality, the permittee shall, for each boiler, conduct performance testing for NOx, VOC, and CO and furnish a written report to Air Quality documenting compliance with emission limitations. Performance testing by the permittee shall use the following test methods specified in 40 CFR Part 60:

i. Method 1: Sample and Velocity Traverses for Stationary Sources.
ii. Method 2: Determination of Stack Gas Velocity and Volumetric Flow rate
iii. Method 3 or 3A: Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.
iv. Method 4: Determination of Moisture in Stack gases.
v. Method 7E: Determination of Nitrogen Oxide Emissions from Stationary Sources.
vi. Method 10: Determination of Carbon Monoxide Emissions from Stationary Sources.
vii. Method 19: F-factor Methodology
viii. Method 25A: Volatile Organic Compounds Emissions From Stationary Sources

Performance testing for NOx and CO shall be conducted while boiler #10 is operating within 10% of its maximum design firing rate, except if the boiler cannot be fired within 10% of the maximum design firing rate due to process limitations and/or production limitations. In those cases, the permittee shall conduct an initial performance test at the maximum firing rate possible under the present operating conditions and within the time guidelines given above. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests.

48. The permittee shall submit an application to update the Title V Permit within 180 days of start-up to incorporate the requirements of this permit. [OAC 252:100-8]

MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(July 21, 2009)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.
[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements.
[OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:

(1)the date, place and time of sampling or measurement;
(2)the date or dates analyses were performed;
(3)the company or entity which performed the analyses;
(4)the analytical techniques or methods used;
(5)the results of such analyses; and
(6)the operating conditions existing at the time of sampling or measurement.

[OAC 252:100-8-6(a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report. [OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions. [OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act. [OAC 252:100-43]

F. Any Annual Certification of Compliance, Semi Annual Monitoring and Deviation Report, Excess Emission Report, and Annual Emission Inventory submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: “I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.”

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1), OAC 252:100-9-7(e), and OAC 252:100-5-2.1(f)]

G. Any owner or operator subject to the provisions of New Source Performance Standards ("NSPS") under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants ("NESHAPs") under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.
[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

H. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality.
[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

J. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM_{10}). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

K. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 C.F.R. Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.
[OAC 252:100-8-6(c)(5)(A), and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.
[OAC 252:100-8-6(c)(5)(C)(i)-(v)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." [OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.
[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification. [OAC 252:100-8-6(c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6(d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.
[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6(a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.
[OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege.
[OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking, reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.

[OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.

[OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.

[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.

[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances: [OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
(3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
(4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d). [OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a "grandfathered source," as defined under AQD rules. Such changes may require a permit modification.

[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6(c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(18) for confidential information submitted to or obtained by the DEQ under this section):

(1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
(3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
(4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

[OAC 252:100-8-6(c)(2)]

SECTION XIV. EMERGENCIES

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.

[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance. [OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that: [OAC 252:100-8-6 (e)(2)]

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
(2) the permitted facility was at the time being properly operated;
(3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

(1) 5 tons per year of any one criteria pollutant.
(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.

[OAC 252:100-8-2 and OAC 252:100, Appendix I]

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.
[OAC 252:100-8-2 and OAC 252:100, Appendix J]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

(1) result in no net emissions increases,
(2) are not modifications under any provision of Title I of the federal Clean Air Act, and
(3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph. [OAC 252:100-8-6(f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

(1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]
(2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]
(3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]
    (a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
    (b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
    (c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
    (d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.

(4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]
(5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]
(6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]
(7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances: [40 CFR 82, Subpart A]

(1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;
(2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and
(3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B: [40 CFR 82, Subpart F]

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158;
(3) Persons performing maintenance, service, repair, or disposal of appliances must be

certified by an approved technician certification program pursuant to § 82.161;

(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;

(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and

(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source's Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.

(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).

(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).

(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R.§ 70.8(a) and (c).

(5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.

(6) The DEQ complies with 40 C.F.R. § 70.8(d).

(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).

(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.

(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).

(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[OAC 252:100-43-6]

PART 70 PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 N. ROBINSON, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit No. 98-014-C (M-19) PSD

Holly Refining & Marketing – Tulsa LLC,

having complied with the requirements of the law, is hereby granted permission to construct Boiler #10 at the Holly Tulsa Refinery West, at 1700 S. Union, Tulsa, Tulsa County, Oklahoma,

subject to the following Standard Conditions dated July 21, 2009, and Specific Conditions, both attached.

In the absence of construction commencement, this permit shall expire 18 months from the issuance date, except as authorized under Section VIII of the Standard Conditions.

_______________________________ _______________________

Director, **Date**

Air Quality Division

Andrew Haar, Environmental Manager
Holly Refining & Marketing – Tulsa LLC
1700 S. Union
Tulsa, OK   74107

Re: Permit No. **98-014-C (M-19) PSD**
Holly Tulsa Refinery West

Dear Mr. Haar:

Enclosed is the modified construction permit authorizing construction of Boiler #10 at the referenced facility. Please note that this permit is issued subject to the standard and specific conditions, which are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Also note that you are required to annually submit an emissions inventory for this facility. An emissions inventory must be completed on approved AQD forms and submitted (hardcopy or electronically) by April 1st of every year. Any questions concerning the form or submittal process should be referred to the Emissions Inventory Staff at 405-702-4100.

Thank you for your cooperation in this matter. If we may be of further service, please contact me at phil.martin@deq.ok.gov or (405) 702-4180.

Sincerely,

Phillip Martin, P.E.
Existing Source Permits Section Manager
Air Quality Division